



Sustainable Performance

**Progress Energy Trust
Annual Report to Unitholders
2006**



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To our Unitholders,

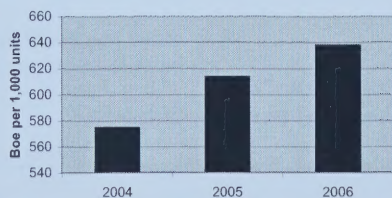
As we reflect on 2006 and look forward to 2007 and beyond, we are left with the clear impression that the future remains strong for oil and gas companies who are well positioned operationally and financially in our sector, regardless of their corporate structure.

Our goal from the first day we converted to an energy trust in 2004 has been to sustain or modestly grow the reserves and production of the Trust through internally generated opportunities while paying out approximately two-thirds of our cash flow in the way of distributions. We have accomplished this entirely through the drill bit as evidenced by the 10 percent growth in our reserves in 2006 and maintaining production in the range of 18,000 boe per day. We have also accomplished this at capital efficiencies that we believe will once again place us amongst the leaders in our industry.

This year we replaced 191 percent of production on a proved plus probable basis and accomplished this at a finding, development and acquisition ("FD&A") cost of \$10.79 per barrel of oil equivalent ("boe"), excluding changes in future development capital. Including \$20 million of change in future development capital, the FD&A cost was \$12.39 per boe. Our reserve base grew by 10 percent to 64.9 million boe from 58.9 million boe while our reserve life index increased to nearly 10 years. Our operating netback in 2006 was \$32.28, generating a recycle ratio of 2.6 times.

Reserves per debt-adjusted unit grew by four percent in 2006 to 638 boe per 1,000 units from 614 boe per 1,000 units in 2005. We have grown reserves per unit at a compound annual rate of five percent since 2004. As I mentioned, this has been accomplished exclusively through the drill bit and is further enhanced by employing our sector-leading capital and operating efficiencies.

Reserve Growth Per Unit

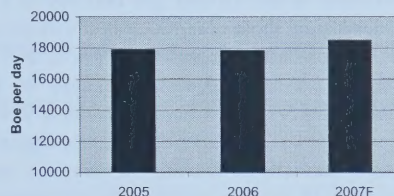


Financially and operationally 2006 was a very strong year. We generated cash flow from operations of \$190.3 million, or \$2.16 per unit, diluted, and made distributions of \$125.6 million, or \$1.68 per unit, for a payout ratio of 66 percent, or 78 percent including the impact of the exchangeable shares. We invested \$134.7 million and ended the year with debt to trailing 12-month cash flow of 1.1 times. We continued to focus on a full cycle exploration and production program by

deploying approximately 15 percent of our capital on land and seismic, building future drilling inventory.

Production averaged 17,853 boe per day in 2006, essentially unchanged from 2005. We exited 2006 at 18,500 boe per day, again, unchanged from our exit rate in 2005. As can be seen on the graph below our production has settled into a consistent, sustainable rate of approximately 18,000 boe per day.

Sustainable Production



This strong financial performance did not translate into an increase in our equity value as the announcement by the Canadian government on October 31, 2006 regarding the taxation of income trusts, beginning in 2011, had the impact of substantially reducing equity values across the trust sector. Clearly we were not immune, having lost 20 percent of our unit price from October 31 to December 31, 2006. Although we showed a positive total return for 2006 up to the October 31 announcement, we ended the year with a negative total unitholder return of 19 percent...unacceptable...but unavoidable given the punitive measures and methods by which the tax change is being implemented by our government. Progress Energy continues to work along side our peers in an attempt to reverse or modify the final rules.

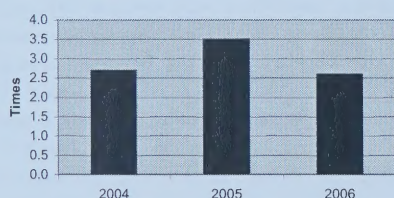
On a per boe basis, our average sales price was \$47.57, before hedging, and \$52.25 per boe including the positive impact of our hedging program. We have used hedging consistently as a means of reducing the volatility of natural gas prices and to provide greater certainty of the cash flow stream supporting our capital program and distributions. Our operating costs were \$6.19 per boe in 2006, which is up nine percent from \$5.69 per boe in 2005, which still places us amongst the lowest cost operators in Western Canada.

As we step into 2007, we are even more resolute in our belief that we can build shareholder value not only through the drill bit, as we have demonstrated historically, but through select acquisitions as well. Strengthening our dominant position in core operating regions remains a clear target and we believe that current commodity prices and the uncertainty in the trust sector may create opportunities to further enhance our asset base through acquisitions.

For 2007, we are targeting average production of between 18,000 and 18,500 boe per day and operating costs in the range of \$6.00 to \$6.50 per boe. Our capital investment program has been set at \$110 million and we anticipate drilling between 55 to 65 net wells. Our distribution has been set for the first quarter of 2007 at \$0.10 per trust unit per month. At this level of distribution we expect to be at the lower end of our historic payout ratio range of 50 to 70 percent. The level of distributions and planned 2007 capital investment program reinforce our commitment to sustainability.

Financial strength in the oil and gas industry is a key element in identifying those companies that will not only weather the fluctuations in commodity prices but also take advantage of periods of general weakness. We have positioned our balance sheet to provide room to execute our capital program while leaving opportunity capital for the right asset acquisition. During the year we issued \$75 million of 6.25 percent convertible debentures to term out a portion of our bank debt which provided additional flexibility on our credit facility.

Strong Recycle Ratio



Throughout our history our asset base has been characterized by four distinct operating areas where we have pursued long-life, unconventional natural gas assets; the Deep Basin of northwest Alberta, the Foothills and Plains regions of northeast British Columbia and the Central Alberta region. In 2006, we established new production records in the Deep Basin, the Foothills and Central Alberta regions. We have focused on these regions because they fit our competencies in multi-zone, tight gas development. The Deep Basin represents approximately 50 percent of our asset base and remains a highly desirable area

because of the multiplicity of producing horizons and the well developed infrastructure. Our growth driver is the Foothills region of northeast British Columbia where we continue to expand our reach in this emerging tight gas region. Since our entry into the Foothills in 2002, Progress and its working interest partner ProEx Energy Ltd., have drilled approximately 130 net wells and added approximately 350 billion cubic feet of natural gas reserves.

On the commodity front, we believe the medium to longer-term outlook for natural gas remains strong because of the increasing challenges the industry has in replacing declining supplies. Very high initial decline rates coupled with shrinking initial productivity mean that our industry must continue to drill at record numbers just to maintain production. On the demand side, weather will continue to be a key factor in consumption patterns for residential and commercial heating load in winter and electric power generation for air conditioning load in the summer.

The trust sector is bound to undergo many changes pending the final passage of the legislation regarding trust taxation. We still view our industry fundamentally, which is to say that the best companies are those that can efficiently add incremental reserves and production and increase the net asset value of every unit or share, regardless of the corporate structure.

On behalf of the management team at Progress, we would like to thank our dedicated employees for once again delivering exceptional results. Our technical, financial and administrative staff are leaders in their respective areas and this has translated into value creation for the Trust and its unitholders. To our Board, we extend our appreciation for their insights and continued support as we work together to increase the value of every unit of Progress Energy Trust.

Sincerely,

(signed) "Michael R. Culbert"
President and Chief Executive Officer

RESERVES

Progress' reserves were prepared by the independent engineering firm of GLJ Petroleum Consultants ("GLJ") in 2006, as well as prior years back to 2001. Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101. The Trust's actual natural gas and petroleum reserves and future production will be greater than or less than the estimates provided. The estimated future net revenue from the production of the Trust's natural gas and petroleum reserves does not represent the fair market value of the Trust's reserves. In addition to the information disclosed in this annual report, more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) is included in the Trust's Annual Information Form.

- Total proved reserves at December 31, 2006 increased 5 percent to 48.2 million boe compared to 46.0 million boe in 2005.
- Total proved plus probable reserves at December 31, 2006 increased 10 percent to 64.9 million boe compared to 58.9 million boe in 2005.
- Reserve growth in 2006 was achieved through the drill bit and replaced 191 percent of production on a proved plus probable basis and 135 percent on a proved basis.

2006 SUMMARY OF OIL AND GAS RESERVES

Forecast Prices and Costs

Company Interest

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	Total 2006	Total 2005
	(mbbls)	(mbbls)	(bcf)	(mmboe)	(mmboe)
Proved					
Developed producing	4,672	3,248	200.1	41.3	37.8
Developed non-producing	100	297	20.3	3.8	4.3
Undeveloped	170	249	16.5	3.2	3.9
Total proved	4,942	3,794	236.9	48.2	46.0
Probable	1,399	1,226	84.2	16.7	13.0
Total proved plus probable	6,341	5,020	321.1	64.9	58.9

Note: May not add due to rounding

Forecast Prices and Costs

Net Present Value of Reserves

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
Proved				
Developed producing	1,274,432	902,459	779,136	717,386
Developed non-producing	114,983	87,194	76,235	70,343
Undeveloped	72,389	49,220	40,346	35,668
Total proved	1,461,804	1,038,873	895,718	823,397
Probable	603,403	310,487	233,555	199,101
Total proved plus probable	2,065,207	1,349,361	1,129,273	1,022,498

Note: May not add due to rounding

Forecast Prices and Costs

Price Assumptions

The January 1, 2007 pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts.

Year	Crude Oil		Natural Gas	Natural Gas	Inflation Rate
	Crude Oil WTI	Edmonton Light	AECO	Sumas Spot	
	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/MMBtu)	(\$US/MMBtu)	(%/Year)
2007	62.00	70.25	7.20	6.60	2.0
2008	60.00	68.00	7.45	6.85	2.0
2009	58.00	65.75	7.75	7.05	2.0
2010	57.00	64.50	7.80	7.05	2.0
2011	57.00	64.50	7.85	7.05	2.0
2012	57.50	65.00	8.15	7.30	2.0
2013	58.50	66.25	8.30	7.45	2.0
2014	59.75	67.75	8.50	7.60	2.0
2015	61.00	69.00	8.70	7.75	2.0
2016	62.25	70.50	8.90	7.95	2.0
2017	63.50	71.75	9.10	8.10	2.0
Thereafter (%/year)	+2.0	+2.0	+2.0	+2.0	+2.0

Constant Prices and Costs

Net Present Value of Reserves

(\$ thousands)	Undiscounted	Discounted At 5%	Discounted At 8%	Discounted At 10%
Proved				
Developed producing	941,525	705,538	620,405	576,276
Developed non-producing	85,109	66,060	58,243	53,975
Undeveloped	48,378	32,955	26,765	23,436
Total proved	1,075,012	804,552	705,414	653,687
Probable	380,033	215,929	167,840	145,278
Total proved plus probable	1,455,045	1,020,481	873,253	798,965

Note: May not add due to rounding

Constant Prices and Costs

Price Assumptions

Year	Crude Oil		Natural Gas	Natural Gas	Inflation Rate
	Crude Oil WTI	Edmonton Light	AECO	Sumas Spot	
	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/MMBtu)	(\$US/MMBtu)	(%/Year)
2007	60.85	67.58	6.07	5.93	0.0

2006 RESERVE RECONCILIATION

Forecast Prices and Costs

Reconciliation of Company Interest Reserves by Principal Product Type

	Light and Medium Crude	Natural Gas	Natural Gas Liquids	Total
	(mmbbl)	(bcf)	(mbbl)	(mmbbl)
Proved Producing				
Opening balance	4,814	179.07	3,134	37.79
Exploration discoveries		0.26	11	0.05
Drilling extensions	66	32.56	483	5.98
Infill drilling	111	7.35	75	1.41
Improved recovery		1.38	55	0.28
Technical revisions	483	11.09	(11)	2.32
Acquisitions				
Dispositions		(0.30)		(0.05)
Production	(802)	(31.30)	(499)	(6.52)
Closing Balance	4,672	200.12	3,248	41.27
Total Proved				
Opening balance	5,839	218.28	3,739	45.96
Exploration discoveries	8	0.83	19	0.17
Drilling extensions	101	41.84	598	7.67
Infill drilling	111	3.95	48	0.82
Improved recovery		1.14	47	0.24
Technical revisions	(316)	3.43	(158)	0.10
Acquisitions				
Dispositions		(1.26)		(0.21)
Production	(802)	(31.30)	(499)	(6.52)
Closing Balance	4,942	236.91	3,794	48.22
Proved Plus Probable				
Opening balance	7,334	280.84	4,781	58.92
Exploration discoveries	11	1.22	27	0.24
Drilling extensions	184	67.89	928	12.43
Infill drilling	126	5.95	76	1.19
Improved recovery		0.66	23	0.13
Technical revisions	(512)	(2.01)	(321)	(1.17)
Acquisitions		0.25	4	0.05
Dispositions		(2.37)		(0.39)
Production	(802)	(31.30)	(499)	(6.52)
Closing Balance	6,341	321.13	5,020	64.88

Note: May not add due to rounding

2006 FINDING, DEVELOPMENT AND NET ACQUISITION COSTS

Finding, development and acquisition costs (“FD&A”) associated with the 2006 capital program, including revisions and the change in future development capital, were \$16.20 per proved boe and \$12.39 per proved plus probable boe. There were no acquisitions or dispositions of a material nature in 2006. Three year average FD&A costs, including revisions and the change in future development capital were \$12.85 per proved boe and \$10.63 per proved plus probable boe. Three year average FD&A costs were negatively affected by the amalgamation of Cequel Energy Inc. and the inclusion of its assets at fair market value in 2004.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	(\$ millions)	(mmboe)	(\$/boe)	(mmboe)	(\$/boe)
Total 2006 proved FD&A costs including future development costs	142	8.78	16.20	n/a	n/a
Total 2006 proved plus probable FD&A costs including future development costs	155	n/a	n/a	12.48	12.39
Three year average proved FD&A costs including future development costs	365	28.41	12.85	n/a	n/a
Three year average proved plus probable FD&A costs including future development costs	379	n/a	n/a	35.66	10.63

Reconciliation of Changes in Future Development Capital

In accordance with NI 51-101, the capital used to calculate FD&A costs has been adjusted to account for the change in future development capital. For that reason the capital may differ between the proved case and the proved plus probable case.

Year	Proved	Change	Proved Plus Probable	Change
2006	34.50	7.58	55.21	19.90
2005	26.93		35.31	

RESERVE LIFE INDEX

The Trust's reserve life index ("RLI") using annualized fourth quarter production is 7.3 years proved (2005 – 6.9 years) and 9.8 years proved plus probable (2005 – 8.8 years).

	2006 Using Annualized Q4 Production	2006 Using 2007 GLJ Forecast Production	2005 Using Annualized Q4 Production	2005 Using 2006 GLJ Forecast Production
Production (mmboe)	6.592	7.091	6.683	6.808
Proved reserves (mmboe)	48.2	48.2	45.96	45.96
Proved RLI (years)	7.3	6.8	6.9	6.8
Production (mmboe)	6.592	7.641	6.683	7.204
Proved plus probable reserves (mmboe)	64.9	64.9	58.92	58.92
Proved Plus Probable RLI (years)	9.8	8.5	8.8	8.2

RESERVE REPLACEMENT

The Trust's 2006 capital program replaced production by a factor of 1.4 times on a proved basis (2005 – 1.5 times) and 1.9 times on a proved plus probable basis (2005 – 1.7 times). Reserve growth in 2005 and 2006 was achieved entirely through the drill bit.

	2006	2005
Production (mmboe)	6.52	6.53
Proved reserve additions (mmboe)	8.78	10.05
Proved placement ratio	1.4	1.5
Proved plus probable reserve additions (mmboe)	12.48	11.18
Proved plus probable replacement ratio	1.9	1.7

RECYCLE RATIO

The recycle ratio is a measure for evaluating the effectiveness of a company's reinvestment program. It accomplishes this by comparing the operating netback per boe to that year's reserve FD&A costs.

	2006	2005
Operating netback (\$/boe)	32.28	34.51
Proved FD&A costs after revisions of prior periods and including the change in future development costs (\$/boe)	16.20	11.36
Proved recycle ratio	2.0	3.0
Proved plus probable FD&A costs after revisions of prior periods and including the change in future development costs (\$/boe)	12.39	9.78
Proved plus probable recycle ratio	2.6	3.5

NET ASSET VALUE

The Trust's net asset value is measured with reference to the present value of future estimated cash flows from reserves estimates prepared by GLJ, the independent reserve engineers, and including undeveloped land, seismic data, adjustments for working capital deficiency, bank debt, convertible debentures and asset retirement obligations at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

	Discounted at 8%		Discounted at 10%	
	2006	2005	2006	2005
	Forecast	Forecast	Forecast	Forecast
	Price	Price	Price	Price
<i>(\$ thousand, except per unit amounts)</i>				
Proved plus probable reserve value(1)	1,129,273	1,070,991	1,022,498	988,243
Undeveloped acreage(2)	81,000	100,000	81,000	100,000
Seismic(3)	36,000	30,000	36,000	30,000
Working capital deficiency	(13,959)	(22,873)	(13,959)	(22,873)
Bank debt	(75,000)	(71,326)	(75,000)	(71,326)
Convertible debentures	(119,605)	(79,381)	(119,605)	(79,381)
Asset retirement obligations(4)	(17,245)	(15,525)	(15,314)	(12,706)
Net asset value	1,020,464	1,011,886	915,620	931,957
Total units outstanding and issuable for exchangeable shares (thousands)	88,114	84,784	88,114	84,784
Net asset value per unit	\$ 11.58	\$ 11.93	\$ 10.39	\$ 10.99

- (1) Reserve values are based on after tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators using their future commodity price forecasts as presented above.
- (2) Based on internal estimate of market value considering recent sales of similar properties in the same general area.
- (3) Seismic inventory values are an internal estimate of replacement value.
- (4) Proved plus probable reserve value includes \$6.9 million and \$5.7 million for the 8% and 10% discounted values, respectively (2005 - \$5.4 and \$4.5 million, respectively) for asset retirement obligations on wells with assigned reserves.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results, dated February 26, 2007, should be read in conjunction with Progress Energy Trust's ("Progress" or the "Trust") accompanying audited consolidated financial statements and related notes for the years ended December 31, 2006 and 2005. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements Management uses cash flow from operations (before changes in non-cash working capital) ("cash flow") to analyze operating performance and leverage. Cash flow presented does not have any standardized meaning prescribed by Canadian GAAP and therefore, it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The reconciliation between net earnings and cash flow can be found in the consolidated statements of cash flows in the audited year end financial statements. The Trust considers cash flow to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investments. Cash flow is used by research analysts to value and compare oil and gas trusts and is frequently included in published research when providing investment recommendations. Cash flow per unit is calculated using the diluted weighted average number of units for the year. All references to cash flow throughout the MD&A are based on cash flow before changes in non-cash working capital.

Management uses certain industry benchmarks such as operating netback and payout ratio to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Forward Looking Statements Certain information regarding Progress set forth in this document, including Management's assessment of Progress' future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Progress' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. Progress' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Progress will derive therefrom.

DESCRIPTION OF BUSINESS

Progress is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties. Progress Energy Ltd., a wholly owned subsidiary of Progress, carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust's unitholders and exchangeable shareholders are the sole beneficiaries of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Progress is a Calgary based, natural gas focused, trust targeting sustainable production and reserves per trust unit through utilization of its technical capability and capital investment efficiencies. Primary operating areas include the Deep Basin of northwest Alberta and the northeast British Columbia Foothills and Fort St. John Plains regions. Trust units of Progress trade on the Toronto Stock Exchange ("TSX") under the symbol PGX.UN. Exchangeable shares and the 6.75 percent and 6.25 percent convertible unsecured subordinated debentures (the "Debentures") of Progress trade on the TSX under the symbols PGE, PGX.DB and PGX.DB.A, respectively.

RELATIONSHIP WITH PROEX

The Trust provides personnel and certain administrative and technical services to ProEx Energy Ltd. (“ProEx”) in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services in accordance with the technical services agreement (“Technical Services Agreement”) entered into with ProEx as described below.

The Trust and ProEx have joint interest in certain properties and undeveloped land in the northeast British Columbia Foothills and Fort St. John Plains regions. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a protocol arrangement (“Protocol Arrangement”) with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

Technical Services Agreement

The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides services including management, development, exploitation, operations, administrative, and marketing, as well as, information technology systems to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx.

Protocol Arrangement

The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The Protocol Arrangement also outlines the practices to be followed in the event either party enters into areas outside of identified areas of interest.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Trust interest basis (working interest plus royalty interest), before deduction of crown and other royalties, unless otherwise indicated. The Trust’s results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions and changes in the Canadian/US currency exchange rate.

In this MD&A, production and reserves information may be presented on a “barrel of oil equivalent” or “boe” basis with six thousand cubic feet (“mcf”) of natural gas being equivalent to one barrel (“bbl”) of crude oil or natural gas liquids. Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well-head.

Production

	2006	2005	Change
Daily Production			
Natural gas (<i>mcf/d</i>)	85,749	82,431	4 %
Crude oil (<i>bbls/d</i>)	2,196	2,779	(21)
Natural gas liquids (<i>bbls/d</i>)	1,366	1,384	(1)%
Total daily production (<i>boe/d</i>)	17,853	17,901	- %
Natural gas as a % of total production	80%	77%	

Production in 2006 averaged 17,853 boe per day consisting of 85,749 mcf per day of natural gas, 2,196 bbls per day of crude oil and 1,366 bbls per day of natural gas liquids. This production was consistent with the 17,901 boe per day produced in 2005 as production additions through the drill bit offset the natural production declines on existing properties and the impact of several scheduled plant maintenance turnarounds during 2006. All production additions during the year were through the drill bit, confirming the Trust’s commitment to sustainable production through drilling. The Trust replaced

191 percent of production on a proved plus probable basis, resulting in a finding, development and acquisition cost of \$12.39 per proved plus probable boe. The Trust's production portfolio in 2006 was weighted 80 percent to natural gas, 12 percent to crude oil and eight percent to natural gas liquids.

Natural gas production in 2006 averaged 85,749 mcf per day compared to 82,431 mcf per day in 2005. The 2006 natural gas production was negatively impacted by scheduled plant maintenance turnarounds in several areas including Karr, Gold Creek-Dunes, Two Creek, Strachan and Gilby in Alberta and the Fort Nelson gas processing facility in British Columbia. The 2005 natural gas production was negatively impacted by a shutdown of the McMahon gas processing facility during the third quarter of 2005. The overall increase in 2006 compared to 2005 was due to the successful drilling program in 2006.

Crude oil and natural gas liquids production in 2006 averaged 3,562 bbls per day compared to 4,163 bbls per day in 2005. The decrease is due to the natural gas focused drilling program, as well as, reduced production due to continued water source and regulatory challenges with the waterflood project in the Halfway 'C' oil pool at Gold Creek. Crude oil production from the Halfway 'C' oil pool averaged approximately 540 bbls per day lower in 2006 compared to 2005.

The Trust had budgeted production for 2006 to be between 18,700 and 19,000 boe per day compared to actual production for the year of 17,853 boe per day. The difference is due to lost production from the Halfway 'C' oil pool as described above, as well as longer gas plant maintenance turnarounds than was originally anticipated.

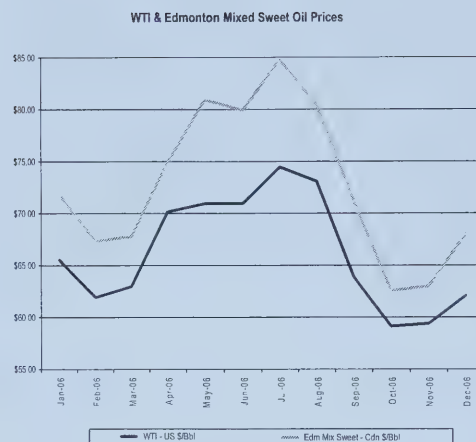
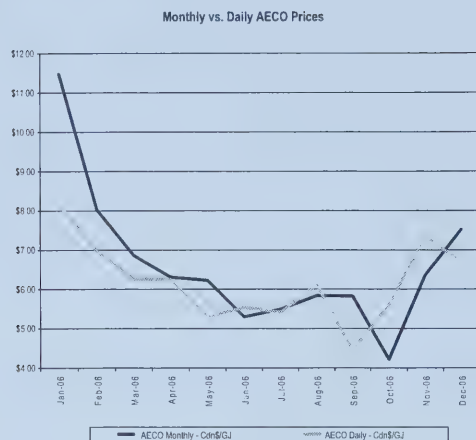
The Trust's 2006 fourth quarter production averaged 18,060 boe per day, comprised of 88,568 mcf per day of natural gas, 2,030 bbls per day of crude oil and 1,269 bbls per day of natural gas liquids. This was consistent with the fourth quarter of 2005 which averaged 18,312 boe per day, comprised of 85,173 mcf per day of natural gas, 2,762 bbls per day of crude oil and 1,355 bbls per day of natural gas liquids. For a full analysis of fourth quarter production refer to the Fourth Quarter Analysis section in this MD&A.

Progress' December 2006 production averaged approximately 18,500 boe per day and Management anticipates production to average between 18,000 and 18,500 boe per day in 2007. This estimate takes into account natural reservoir declines and forecasted capital expenditures of \$110.0 million.

Production by Region

<i>(boe/d)</i>	Fourth Quarter 2006	Fourth Quarter 2005	Change	2006	2005	Change
Foothills	3,769	3,690	2 %	3,690	3,415	87 %
Fort St. John Plains	2,118	2,117	- %	2,098	1,981	6 %
Other	348	449	(22)%	369	501	(26)%
Total British Columbia	6,235	6,256	- %	6,157	5,897	4 %
Deep Basin	9,099	8,957	2 %	8,825	8,999	(2)%
Central Alberta	1,714	1,440	19 %	1,742	1,461	19 %
Other	736	1,236	(40)%	803	1,107	(27)%
Total Alberta	11,549	11,633	(1)%	11,370	11,567	(2)%
Saskatchewan	276	423	(35)%	326	437	(25)%
Total daily production	18,060	18,312	(1)%	17,853	17,901	- %

Pricing and Risk Management



The year 2006 began with falling natural gas prices as a result of the record warm temperatures in January and prices remained on a downward trend through much of the first six months. Minimal natural gas storage withdrawals and seasonably low natural gas demand continued to put downward pressure on prices but was partially offset by strong crude oil prices. June marked the beginning of the hurricane season but in spite of dire warnings from the forecasters, no significant storms made land-fall in 2006.

The third quarter started with a heat wave across much of the United States ("US") which resulted in record high levels of gas consumption, as well as the first ever recorded withdrawal of natural gas from storage during the summer. Crude oil prices began the third quarter with West Texas Intermediate ("WTI") averaging a record high of US\$74.46 per bbl due to supply concerns and a significant "risk premium" related to Middle East tensions. Oil prices softened through the balance of the third quarter and continued through the fourth quarter as crude oil and refined products inventories remained high and Middle East tensions eased. By year end, crude oil prices had averaged a new annual record of US\$66.22 per bbl for WTI.

For natural gas, the fourth quarter began with prices at their lowest levels in many months. Natural gas storage facilities were filled to record levels and winter weather had not begun to absorb the excess supply. However, the weather turned cold the first week of December which created several weeks of large storage withdrawals and strengthened gas prices. By mid December, the cold gave way to above normal temperatures. In spite of the high storage volume and resulting oversupply of natural gas, prices for 2006 averaged US\$7.26 per million btu for the New York Mercantile Exchange ("NYMEX") and Cdn\$6.17 per gigajoule ("gj") at the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system ("AEEO").

Looking toward 2007, we anticipate WTI oil prices will average within the US\$55.00 to US\$65.00 per bbl range and natural gas at AEEO is expected to average between Cdn\$6.00 to Cdn\$8.00 per gj. Progress produces predominantly light oil and high heat content liquids rich natural gas that attract premium market prices.

Commodity Prices

	2006	2005	Change
Average Benchmark Prices			
Natural gas - AECO (daily) (\$/gj)	6.17	8.26	(25)%
Natural gas - AECO (monthly) (\$/gj)	6.62	8.04	(18)%
Crude oil - WTI (US\$/bbl)	66.22	56.56	17 %
Crude oil - Edmonton par price (Cdn\$/bbl)	72.74	68.76	6 %
Exchange rate - (US\$/Cdn\$)	1.1343	1.2114	(6)%
Average Realized Prices			
Natural gas - before hedging (\$/mcf)	7.17	9.27	(23)%
Hedging settlements (\$/mcf)	1.08	(0.17)	
Amortization of hedge premiums (\$/mcf)	(0.13)	(0.01)	
Amortization of commodity sales contract (\$/mcf)(1)	0.02	0.02	
Natural gas - after hedging (\$/mcf)	8.14	9.11	(11)%
Crude oil (\$/bbl)	67.88	65.98	3 %
Natural gas liquids (\$/bbl)	62.65	57.20	10 %

(1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

Natural Gas Pricing

US natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of Progress' natural gas is sold at market prices at one of the Alberta or British Columbia hubs. Progress typically sells 50 percent of its natural gas production on monthly indexes and 50 percent on daily indexes.

Natural Gas Production and Prices by Province

	2006		2005	
	mcf/d	\$mcf	mcf/d	\$/mcf
Alberta	54,268	7.32	52,059	9.39
British Columbia	30,882	6.93	29,198	9.12
Saskatchewan	599	6.47	1,174	7.83
Total production and average sales price(1)	85,749	7.17	82,431	9.27

(1) Before the impact of hedging

Alberta Natural Gas Prices

	2006	2005
NYMEX (US\$/mmbtu 12 month average – last 3 days)	7.26	8.55
Less: AECO basis differential to Henry Hub (US\$/mmbtu)	(1.52)	(1.36)
AECO (US\$/mmbtu)	5.74	7.19
Average exchange rate	1.1343	1.2114
AECO price (Cdn\$/mmbtu daily average)	6.51	8.71
Premium: Progress realized price vs spot(1)	0.81	0.68
Progress average realized Alberta price (Cdn\$/mcf)	7.32	9.39

(1) Includes the conversion of mmbtu's to mcf.

British Columbia Natural Gas Prices

	2006	2005
NYMEX (US\$/mmbtu 12 month average – last 3 Days)	7.26	8.55
Less: Station #2 basis differential to Henry Hub (US\$/mmbtu)	(1.78)	(1.50)
Station #2 (US\$/mmbtu)	5.48	7.05
Average exchange rate	1.1343	1.2114
Station #2 price (Cdn\$/ mmbtu daily average)	6.22	8.54
Premium: Progress realized price vs. spot(1)	0.71	0.58
Progress average realized British Columbia price (Cdn\$/mcf)	6.93	9.12

(1) Includes the conversion of mmbtu's to mcf.

Price Risk Management

The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange.
- To provide greater certainty and stability to monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production before royalties.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

In 2006, the Trust entered into a number of financial instruments to hedge its exposure to natural gas prices, specifically swap and call spread transactions. For 2006, the Trust's natural gas price risk management program had a net gain of \$29.9 million (2005 - \$5.7 million net loss) which is included in petroleum and natural gas revenue. Progress' commodity risk management positions are described in note 10 in the consolidated financial statements attached. At December 31, 2006, the Trust would have received \$14.0 million on the termination of its natural gas financial contracts.

The Trust currently has natural gas financial contracts in place for the following production volumes:

Financial Price Risk Management	Contract Natural Gas Volumes ('000 gj/d)	% of Estimated Natural Gas Production
First quarter of 2007	40.0	42
Second quarter of 2007	40.0	42
Third quarter 2007	40.0	42
Fourth quarter 2007	13.5	15

Sensitivities

The Trust's risk management program will reduce, but not eliminate, the effects of changing commodity prices and exchange and interest rates and as a result cash flow remains sensitive to these changes as demonstrated by the following table:

	Estimated Effect on 2007(1) Cash Flow per Trust Unit
Change of \$0.25 per mcf in the price of natural gas	\$0.07
Change of US\$5.00 per barrel in the price of WTI	\$0.05
Change of 5,000 mcf/d in natural gas production	\$0.09
Change of 500 bbls/d in crude oil production	\$0.08
Change of \$0.01 in the US\$/Cdn\$ exchange rate	\$0.03
Change of 1% in prime interest rates	\$0.02

- (1) These sensitivities reflect all commodity contracts as described in Note 10 of the consolidated financial statements. They apply to prices, production, interest and exchange rates within the context of current market rates. The sensitivities above will no longer apply above the ceiling or below the floor price limits set by existing natural gas financial contracts.

Revenue

Petroleum and natural gas revenue decreased eight percent to \$340.5 million in 2006 from \$369.8 million in 2005 mainly due to lower natural gas prices in the fourth quarter of 2006 compared to the fourth quarter of 2005. Production of 17,853 boe per day in 2006 was consistent with production in 2005 of 17,901 boe per day while realized commodity prices decreased eight percent from \$56.59 per boe in 2005 compared to \$52.25 per boe in 2006, including the impact of hedging. Petroleum and natural gas revenue in 2006 before hedging consisted of \$224.3 million from natural gas sales, \$54.4 million from crude oil sales and \$31.2 million from the sale of natural gas liquids. In 2006, Progress realized a net hedging gain of \$29.9 million compared to a \$5.7 million net loss in 2005 which are included in petroleum and natural gas revenue.

(\$ thousands)	2006	2005	Change
Natural gas sales	224,322	278,978	(20)%
Crude oil sales	54,402	66,914	(19)%
Natural gas liquids sales	31,224	28,887	8 %
Hedge settlements	33,955	(5,217)	751 %
Hedge premiums	(4,018)	(442)	(809)%
Amortization of a commodity sales contract(1)	570	648	(12)%
Petroleum and natural gas revenue	340,455	369,768	(8)%

- (1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

(\$ thousands)	Natural Gas	Crude Oil & NGLs	Total
2005 Petroleum and natural gas revenue	273,967	95,801	369,768
Price variance	(30,166)	3,656	(26,510)
Production variance	11,028	(13,831)	(2,803)
2006 Petroleum and natural gas revenue	254,829	85,626	340,455

Royalties

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners, net of credits received through the Alberta royalty tax credit program. Effective for 2007, the Alberta government eliminated the Alberta royalty tax credit program. The estimated impact to Progress will be an increase to royalty expense in 2007 of approximately \$0.5 million.

Royalties decreased 17 percent to \$78.8 million in 2006 from \$94.5 million in 2005 due to the decrease in natural gas prices. The Trust's average royalty rate in 2006 was 25.4 percent (before the impact of hedging charges) which is consistent with the average royalty rate in 2005 of 25.2 percent.

<i>(\$ thousands)</i>	2006	2005
Crown	64,544	81,508
Freehold and overriding	14,218	12,984
Total royalty expense	78,762	94,492
Royalties (\$/boe)	12.09	14.46
Average royalty rate (after impact of hedging charges- %)	23.1	25.5
Average royalty rate (before impact of hedging charges- %)	25.4	25.2

The following table provides a break down of royalties by product. Rates are calculated before the impact of hedging activities:

<i>(\$ thousands)</i>	2006	2005
Natural gas royalties	56,945	71,530
\$/boe	10.92	14.26
Average natural gas royalty rate(%)	25.4	25.6
Crude oil royalties	12,856	13,979
\$/boe	16.04	13.78
Average crude oil royalty rate(%)	23.6	20.9
Natural gas liquids royalties	8,961	8,983
\$/boe	17.97	17.78
Average natural gas liquids royalty rate(%)	28.7	31.1

Management anticipates, based on current commodity prices that the average royalty rate for 2007, before the impact of hedging, will be approximately 26.5 percent of petroleum and natural gas revenue.

Operating Expenses

Operating expenses increased nine percent to \$40.4 million in 2006 compared to \$37.2 million in 2005. The increase in operating expenses is mainly attributable to increased plant turnaround costs in 2006 compared to 2005. On a boe basis, operating expenses for 2006 increased nine percent to \$6.19 from \$5.69 in 2005. Progress has experienced increased costs for well servicing, insurance, workovers and well maintenance. Through increased operating efficiencies and the addition of low operating cost per boe production, the Trust has been able to offset a large portion of these increases and keep operating costs per boe low. Management anticipates continuing this trend and forecasts operating expenses for 2007 to be between \$6.00 to \$6.50 per boe.

<i>(\$ thousands)</i>	2006	2005	Change
Operating expenses - total	40,353	37,170	
\$/boe	6.19	5.69	9%
Operating expenses - natural gas properties	31,381	27,505	
\$/boe	5.62	5.14	9%
Operating expenses - crude oil properties	8,972	9,665	
\$/boe	9.61	8.17	18%

Transportation Expenses

Transportation expenses decreased 12 percent to \$11.0 million in 2006 compared to \$12.6 million in 2005. The decrease is due to reduced tolls negotiated with Spectra Energy Corp ("Spectra Energy") (formerly Duke Energy) in 2006, as well as lower oil production in 2006 which incurs higher transportation costs. On a boe basis, transportation expenses in 2006 decreased 12 percent to \$1.69 compared to \$1.93 in 2005. In British Columbia, there is an infrastructure owned by Spectra Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas properties, oil properties and all properties combined:

	2006	2005
Natural Gas Properties (\$/mcf)		
Sales price – before hedging	7.51	9.33
Hedging settlements	1.01	(0.16)
Amortization of hedge premiums	(0.12)	(0.01)
Amortization of commodity sales contract	0.02	0.02
Royalties	(1.94)	(2.40)
Operating expenses	(0.94)	(0.86)
Transportation expenses	(0.28)	(0.32)
Operating netback – natural gas properties	5.26	5.60
Oil Properties (\$/bbl)		
Sales Price	62.62	63.52
Royalties	(14.74)	(14.65)
Operating expenses	(9.61)	(8.17)
Transportation expenses	(1.89)	(1.88)
Operating netback – oil properties	36.38	38.82
All Properties (\$/boe)		
Sales Price – before hedging	47.57	57.36
Hedging settlements	5.21	(0.80)
Amortization of hedge premiums	(0.62)	(0.07)
Amortization of commodity sales contract	0.09	0.10
Royalties	(12.09)	(14.46)
Operating expenses	(6.19)	(5.69)
Transportation expenses	(1.69)	(1.93)
Operating netback – all properties	32.28	34.51

General and Administrative Expenses

General and administrative expenses net of overhead recoveries on operated properties, (“G&A”) decreased six percent to \$6.3 million (\$0.97 per boe) in 2006 compared to \$6.7 million (\$1.03 per boe) in 2005. The decrease in G&A expense is due to higher technical service fees received from ProEx as a result of its increased production in 2006 compared to 2005.

(\$ thousand)	2006	2005
Gross G&A	16,171	14,962
Technical Services Fees from ProEx	(4,484)	(2,759)
Operator recoveries	(4,132)	(4,112)
Capitalized expenses	(1,234)	(1,345)
Total G&A expense	6,321	6,746
G&A (\$/boe)	0.97	1.03

In accordance with the Technical Services Agreement with ProEx, the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expenses reimbursed by ProEx in 2006 were \$4.5 million compared to \$2.8 million in 2005.

The magnitude of operator recoveries is a function of activity levels and the degree to which operations are operated by the Trust. Progress operates 82 percent of its production and operates the majority of the drilling and construction activity. Operator recoveries of \$4.1 million for 2006 were consistent with 2005.

The Trust capitalized approximately \$1.2 million of G&A in 2006 and \$1.4 million in 2005. The majority of these costs represent geological and geophysical employee compensation.

Management anticipates G&A expense to remain consistent with 2006 and average in the range of \$1.00 to \$1.20 per boe in 2007.

Unit Based Compensation Expenses

The Trust’s Performance Unit Incentive Plan (the “Plan”) provides for employees and directors to be granted performance units by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units vest on the third anniversary of the date of grant and actual payment will be based on a performance factor ranging from 0.5 to 1.5 times the initial performance units granted which will be determined based on the performance of the Trust relative to its peers. The performance units entitle the employee or director to a specific number of trust units and the accumulated distributions those trust units earned over the three year vesting period. Payment may be in the form of cash or trust units, at the Trust’s option. Management anticipates, at the end of the performance period, accumulated distributions will be paid in cash and trust units will be paid from treasury.

As at December 31, 2006 there are 380,567 performance units outstanding that were granted effective July 2, 2004. As a result, the fair value of the performance units granted, calculated using a performance factor of 1.0, was approximately \$5.1 million of which \$4.5 million will be amortized through unit based compensation expense and \$0.6 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

As at December 31, 2006 there are 512,300 performance units outstanding that were granted effective July 2, 2005. The fair value of the performance units using a performance factor of 1.0 was approximately \$8.1 million of which \$7.0 million will be amortized through unit based compensation expense and \$1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

As at December 31, 2006 there are 407,850 performance units outstanding that were granted effective July 2, 2006. The fair value of the performance units using a performance factor of 1.0 was approximately \$6.5 million of which \$5.6 million will be amortized through unit based compensation expense and \$0.9 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the year ended December 31, 2006 \$4.9 million (\$0.75 per boe) was charged to unit based compensation expense compared to \$3.0 million in 2005 (\$0.46 per boe) and \$0.8 million (2005 – \$0.3 million) was capitalized relating to the total performance units outstanding. The increase over 2005 is due to the performance units granted in July 2006.

	2006	2005
Performance Units		
Balance, beginning of year	899,567	395,267
Granted	424,950	511,500
Forfeited	(23,800)	(7,200)
Balance, end of year	1,300,717	899,567
Vesting Date		
July 2, 2007	380,567	388,067
July 2, 2008	512,300	511,500
July 2, 2009	407,850	—
Total	1,300,717	899,567

Management anticipates unit based compensation expenses will increase to approximately \$0.95 per boe in 2007.

Interest and Financing Expenses

Interest and financing expenses in 2006 increased 11 percent to \$11.8 million compared to \$10.6 million in 2005. The increase is primarily due to higher interest rates in 2006 compared to 2005. Debenture interest, accretion and amortized issue costs relate to two debenture issues; the 6.75 percent debentures issued on February 2, 2005 and the 6.25 percent debentures issued on August 22, 2006 (the “Debentures”). For more information regarding the Debentures, see the “Liquidity and Capital Resources” section below.

<i>(\$ thousands)</i>	2006	2005
Interest on bank debt	4,406	3,030
Interest on Debentures	5,803	6,012
Amortization of Debenture issue costs	717	754
Accretion on debt portion of Debentures(1)	872	793
Total interest and financing expense	11,798	10,589
Interest and financing expense (\$/boe)	1.81	1.62
Average bank debt outstanding	86,622	73,581
Average bank debt interest rate (%)	5.1	4.2

(1) Under Canadian GAAP, the fair value of the conversion feature of the Debentures is classified as equity and the remainder is classified as debt. Over the term of the Debentures, the debt portion will accrete up to the principal balance at maturity with the charge going to interest and financing expenses.

Depletion, Depreciation and Accretion

Depletion and depreciation of property, plant and equipment and the accretion of the asset retirement obligations (“DD&A”) of \$94.7 million in 2006 was consistent with the 2005 provision of \$92.0 million. DD&A per boe in 2006 of \$14.53 was slightly higher than the \$14.09 recognized in 2005. The slight increase is due to a higher depletable base in 2006, including a charge of \$13.5 million during the year to property, plant and equipment related to the redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders, which must be accounted for as a non-cash step-purchase under Canadian GAAP.

(\$ in thousands)	2006	2005
Depletion	92,287	89,956
Depreciation	671	637
Accretion of asset retirement obligations	1,750	1,447
Total DD&A expense	94,708	92,040
DD&A (\$/boe)	14.53	14.09

Income and Capital Taxes

Capital taxes were \$0.2 million in 2006 and \$2.2 million in 2005. The decrease is due to the federal budget passed in June of 2006 which eliminated the large corporation tax effective for the 2006 taxation year.

The provision for future income taxes in 2006 decreased to a recovery of \$14.7 million from an expense of \$4.1 million in 2005 due primarily to a tax rate reduction in 2006. The 2006 provision includes a recovery of \$9.2 million relating to a reduction in future federal and provincial income tax rates enacted during the year and the impact of certain tax balance adjustments. The 2005 provision includes a charge of \$3.5 million due to adjustments relating to tax audits performed on the 2002 and 2003 tax returns for both Cequel Energy Inc. and Progress Energy Ltd. and a recovery of approximately \$2.0 million due to a reduction in the British Columbia provincial income tax rate. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to unitholders, no provision for income taxes has been made for the Trust. The federal government has proposed new rules for the taxation of trusts as outlined below. The future income tax liability on the consolidated balance sheet represents the future income tax liability of the Trust’s subsidiary.

On October 31, 2006 the federal government announced its intention to begin taxing distributions from trusts beginning January 1, 2011. The government has also proposed to limit the growth of existing trusts by limiting new equity issues to 40 percent of that trust’s October 31, 2006 market capitalization (“benchmark”) for 2007, and an additional 20 percent of the benchmark for each of 2008, 2009 and 2010. For Progress, the growth limits would be \$476.8 million for 2007 and \$238.4 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year. The government also announced its intention to allow trust to corporation conversions to be on a tax-deferred basis (no immediate tax impact) for unitholders. Given these proposed rules have not been substantially enacted into law, there has been no adjustment to future income taxes in regards to this announcement. The Trust is currently monitoring the status of this proposed legislation and assessing its options should it pass into law.

Non-Controlling Interest – Exchangeable Shares

The exchangeable shares of the Trust’s subsidiary trade on the TSX, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders’ equity. The net earnings attributable to the exchangeable shares is charged to the consolidated statements of earnings as non-controlling interest expense with a corresponding increase to non-controlling interest on the consolidated balance sheet.

The following details the non-controlling interest activity for the years ended December 31, 2006 and 2005:

(\$ thousand, except per unit amounts)	2006		2005	
	Number	Amount	Number	Amount
Exchangeable Shares				
Balance, beginning of year	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,746,211)	(20,130)	(3,144,755)	(31,816)
Non-controlling interest expense		15,517		17,961
Balance, end of year	9,642,540	122,592	11,388,751	127,205

The charge to net earnings of \$15.5 million for 2006 and \$18.0 million for 2005 represents the net earnings attributable to the exchangeable shares.

Net Earnings and Cash Flow

Net earnings increased three percent to \$91.6 million in 2006 compared to \$88.9 million in 2005. The increase was primarily the result of a higher future income tax recovery in 2006 compared to 2005. Basic net earnings in 2006 were \$1.23 per trust unit compared to \$1.29 per trust unit in 2005. Diluted net earnings in 2006 were \$1.21 per trust unit compared to \$1.27 per trust unit in 2005.

Cash flow decreased eight percent to \$190.3 million in 2006 compared to \$206.0 million in 2005 mainly due to lower commodity prices, particularly in the fourth quarter compared to the fourth quarter of 2005. Diluted cash flow in 2006 was \$2.16 per trust unit compared to \$2.45 per trust unit in 2005.

Quarterly Financial Summary(1),(2)

(\$ thousand, except per unit amounts)	Three Months Ended							
	Dec. 31 2006	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	Jun. 30 2005	Mar. 31 2005
Petroleum and natural gas revenue	85,633	82,854	81,009	90,959	114,167	93,372	83,222	79,007
Cash flow	49,603	47,218	45,871	47,637	65,785	53,215	44,466	42,511
Per unit diluted	0.56	0.54	0.52	0.55	0.77	0.63	0.53	0.52
Net earnings	21,538	20,252	28,425	21,383	29,398	25,159	16,840	17,527
Per unit basic	0.29	0.27	0.38	0.29	0.41	0.36	0.25	0.27
Per unit diluted	0.28	0.27	0.38	0.29	0.40	0.36	0.24	0.27

(1) The above amounts have been restated for the change in accounting policy related to non-controlling interest.

(2) Quarterly petroleum and natural gas revenue, cash flow and net earnings increased in the second, third and fourth quarters of 2005 primarily as a result of increasing commodity prices. Petroleum and natural gas revenue and cash flow for each quarter of 2006 decreased as a result of lower natural gas prices compared to the third and fourth quarters of 2005. Net earnings for the second quarter of 2006 includes an \$8.2 million future income tax recovery due to reduced future tax rates enacted during that quarter.

SELECTED ANNUAL INFORMATION

<i>(\$ thousands, except per unit amounts)</i>	2006	2005	2004
Petroleum and natural gas revenue	340,455	369,768	214,689
Net earnings	91,598	88,924	44,231
Per unit basic	1.23	1.29	0.89
Per unit diluted	1.21	1.27	0.88
Cash flow	190,329	205,977	110,460
Per unit diluted	2.16	2.45	1.87
Total assets	1,210,704	1,152,985	1,093,268
Distributions declared	125,563	116,460	55,705
Working capital deficiency	13,959	22,873	37,820
Bank debt	75,000	71,326	133,722
Convertible debentures	119,605	79,381	-
Total debt	208,564	173,580	171,542

Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted cash flow, debt levels and capital expenditures. Historically Progress has distributed approximately 50 to 70 percent of its annual cash flow to unitholders and retained the remaining cash flow for capital expenditures and debt repayment. The Trust distributed 66 percent of cash flow to unitholders in 2006 (78 percent including exchangeable shares). In 2005 the Trust distributed 57 percent of cash flow to unitholders (69 percent including exchangeable shares). Exchangeable shares are convertible into trust units of the Trust based on the exchange ratio. The exchange ratio is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and the cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. The key drivers of Progress' cash flow, as is generally the case with other energy trusts, are commodity prices and production. Since the Trust's production is heavily weighted to natural gas (80 percent in 2006), natural gas prices have a significant effect on its cash flow.

Progress' initial cash distribution declared was \$0.14 per trust unit for the month of July 2004. The Trust has maintained this cash distribution to December 31, 2006. As a result, \$125.6 million of distributions were declared in 2006 compared to \$116.5 million in 2005. In January 2007, the Trust announced that distributions for the first quarter of 2007 are expected to be \$0.10 per trust unit per month which reinforces the Trust's commitment to sustainability and positions it to take advantage of opportunities that may arise in the current commodity price environment. As a result of this reduced distribution, Management expects its payout ratio to be at the lower end of its historical payout range.

Capital Expenditures

The Trust invested approximately \$134.7 million in capital expenditures in 2006 compared to \$107.7 million in 2005.

<i>(\$ thousands)</i>	2006	2005
Land acquisitions and retention	11,936	8,340
Geological and geophysical	5,892	4,442
Drilling and completions	82,611	70,230
Equipping and facilities	31,926	23,932
Net property acquisitions (dispositions)	766	(334)
Corporate assets	1,521	1,048
Total capital expenditures	134,652	107,658

Progress drilled 106 gross wells (62.1 net) with a 97 percent success rate in 2006. Included in this drilling activity was 26 gross wells (21.8 net) drilled in the Deep Basin region of northwest Alberta, 38 gross wells (12.0 net) in the Foothills region of northeast British Columbia, seven gross wells (3.7 net) in the Fort St. John Plains region of northeast British Columbia and 33 gross wells (22.6 net) in central Alberta. Progress began 2006 with a capital budget for the year of \$100.0 million. Given the drilling success and expansion activity during the year, the capital budget was increased to \$115.0 million in the second quarter and increased again in the third quarter to \$125.0 million for 2006. The successful 2006 capital program resulted in a proved plus probable finding, development and acquisition cost of \$12.39 per boe.

In June 2006, the Trust disposed of its petroleum and natural gas assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at \$1.20 per share for a total consideration of \$3.4 million. As this was a non-cash transaction, it is excluded from the table above.

The 2007 capital investment program will be directed to the Trust's three focus regions; the Deep Basin in northwest Alberta and the Fort St. John Plains and Foothills regions of northeast British Columbia. Progress expects to drill 55 to 65 net wells on a capital program totaling \$110.0 million. The Trust's capital investment program is expected to be split approximately 65 percent to drilling and completions, 20 percent to major facilities and 15 percent to land and seismic expenditures. The Trust does not set a budget for property acquisitions.

Undeveloped Land

Undeveloped land at December 31, 2006 decreased 28 percent compared to December 31, 2005 due to the sale of the Trust's assets in the Unity, Saskatchewan area, as well as, conversions to developed land, expiries and a conversion of working interest land to royalty acreage. The Trust purchased approximately 46,000 net acres at Crown land sales during 2006 and acquired 4,900 net freehold acres in Progress' core regions.

	2006	2006	2005	2005
(acres)	Gross	Net	Gross	Net
Alberta	248,418	203,431	345,660	288,019
British Columbia	409,858	156,697	336,868	158,498
Saskatchewan	3,674	2,615	56,783	55,684
Total undeveloped land	661,950	362,743	739,311	502,201

Over the next 12 months 74,000 net acres or 20 percent of Progress' undeveloped land will be subject to expiry. The Trust has an active capital program and farmout strategy in place with 33,500 net acres of undeveloped land committed under farmout agreements at normal industry terms during 2006.

Goodwill

The goodwill balance of \$414.7 million is primarily the result of the acquisition of Cequel in 2004. In accordance with Canadian GAAP, goodwill is not amortized but is subject to an impairment test. Progress conducts a goodwill impairment test on an annual basis at its fiscal year end. Goodwill may be tested for impairment between annual tests in certain situations. There was no impairment of goodwill as a result of the tests conducted at December 31, 2006 and 2005.

Liquidity and Capital Resources

(\$ thousands except per unit amounts)	2006	2005
Working capital deficiency	13,959	22,873
Bank debt	75,000	71,326
Convertible debentures	119,605	79,381
Total debt	208,564	173,580
Units outstanding and issuable for exchangeable shares (thousands)	88,114	84,784
Market price per unit at end of year	12.57	17.17
Market value of trust units and exchangeable shares	1,107,593	1,455,741
Cash flow	190,329	205,977
Total debt to cash flow ratio	1.10	0.84

At December 31, 2006 the Trust had \$75.0 million outstanding on its credit facility of \$215.0 million, as well as \$119.6 million for the debt portion of the Debentures and a working capital deficiency of \$14.0 million, resulting in \$208.6 million of total debt. The Trust currently has a \$200 million extendible revolving term credit facility and a \$15 million working capital credit facility with a syndicate of banks. The facilities are available on a revolving basis for a period of at least 364 days until May 29, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The credit facilities are secured by a \$500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and

subordination provided by Progress Energy Ltd. in respect of the Trust's obligations. The \$215 million borrowing base is subject to semi-annual review by the banks.

Bank debt of \$75.0 million as at December 31, 2006 was consistent with the December 31, 2005 bank debt of \$71.3 million. Working capital deficiency decreased from \$22.9 million as at December 31, 2005 to \$14.0 million as at December 31, 2006 as a result of a decrease in accounts payable and accrued liabilities due to the timing of invoice payments.

On August 22, 2006 the Trust issued \$75 million principal amount of 6.25 percent convertible unsecured subordinated debentures for net proceeds of \$71.7 million. The 6.25 percent debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011 at which time they become due and payable. Interest and principal repayments may be made by way of cash or trust units. The net proceeds were used to reduce outstanding bank indebtedness.

On February 2, 2005 the Trust issued \$100 million principal amount of 6.75 percent convertible unsecured subordinated debentures for net proceeds of \$95.5 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable. Interest and principal repayments may be made by way of cash or trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The Debentures have been classified as debt net of the fair value of the conversion feature which has been classified as part of unitholders' equity and net of issue costs. For the 6.25 percent debentures, this resulted in \$66.7 million being classified as debt and \$4.9 million being classified as equity. For the 6.75 percent debentures, \$90.5 million was originally classified as debt and \$4.9 million was classified as equity. Issue costs are amortized over the term of the Debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings.

The following table outlines the Debenture activity for the years ended December 31, 2006 and 2005:

Debentures	2006			2005		
	6.75%	6.25%	Total	6.75%	6.25%	Total
Principal, beginning of year(1)	86,182	75,000	161,182	100,000	-	100,000
Converted to trust units	(30,455)	-	(30,455)	(13,818)	-	(13,818)
Principal, end of year	55,727	75,000	130,727	86,182	-	86,182
Debt portion, beginning of year(1)	79,381	66,748	146,129	90,541	-	90,541
Accretion	535	337	872	793	-	793
Amortization of issue costs	497	220	717	755	-	755
Conversions to trust units(2)	(28,113)	-	(28,113)	(12,708)	-	(12,708)
Debt portion, end of period	52,300	67,305	119,605	79,381	-	79,381
Equity portion, beginning of year(1)	4,261	4,946	9,207	4,944	-	4,944
Conversions to trust units	(1,505)	-	(1,505)	(683)	-	(683)
Equity portion, end of year	2,756	4,946	7,702	4,261	-	4,261

(1) The 6.75 percent debentures were issued February 2, 2005 and the 6.25 percent debentures were issued August 22, 2006.

(2) Net of unamortized issue costs.

The Trust's investing activities for 2006 primarily consisted of expenditures on the capital program. Management anticipates that the Trust will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2007 through a combination of cash flow and debt. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Outstanding as at February 23, 2007 were 75,753,281 trust units, 9,419,514 exchangeable shares and \$130.7 million of Debentures convertible into 7,561,287 trust units.

Off Balance Sheet Arrangements

The Trust has no guarantees or off-balance sheet arrangements except for certain lease agreements, derivative financial instruments and letters of credit. The Trust has certain lease agreements that are entered into in the normal course of

operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at December 31, 2006. The total future obligation from these operating leases is described below in the section "Contractual Obligations and Commitments".

The Trust has entered into derivative financial instruments to hedge future natural gas sales and has committed to pay the associated premiums of these contracts. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. The contracts currently in place are disclosed in note 10 to the consolidated financial statements. Future premium obligations are described below under "Contractual Obligations and Commitments".

Letters of credit of approximately \$1.4 million as at December 31, 2006 have been issued in the normal course of business mainly for contract firm transportation.

Unitholders' Equity

At December 31, 2006, there were 88.1 million trust units issued and issuable for exchangeable shares, a four percent increase from the 84.8 million trust units issued and issuable for exchangeable shares at December 31, 2005. The increase in the number of trust units and issuable exchangeable shares is the result of 2.0 million trust units issued on the conversion of Debentures and the increase in the conversion ratio of exchangeable shares.

Contractual Obligations and Commitments

The Trust contracts for firm transportation on the TransCanada and Atco systems in Alberta and the Spectra Energy system in British Columbia. The Trust has an office lease commitment that extends to 2009. Annual costs of this lease commitment, which include rent and operating expenses, amount to \$1.5 million.

The Trust must pay crown royalty, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Production of 4,100 mcf per day is dedicated to certain aggregator sales arrangements. Under these arrangements, Progress receives a price based on the average netback price of the pool, net of transportation expenses incurred by the aggregator.

(\$ thousands)	Total	Minimum Annual Commitment			
		2007	2008	2009-2010	2011-2012
Bank debt(1)	75,000	-	75,000	-	-
Convertible debentures	130,727	-	-	55,727	75,000
Pipeline commitments	28,848	7,324	6,791	11,247	3,486
Drilling rig commitments	10,592	8,271	2,321	-	-
Operating leases	996	663	333	-	-
Financial instrument premiums	4,793	4,793	-	-	-
Office lease	4,191	1,479	1,479	1,233	-
Total	255,147	22,530	85,924	68,207	78,486

- (1) Based on the existing terms of the revolving credit facilities which are subject to renewal on or before May 29, 2007. If not extended, the facilities would be available on a non-revolving basis for a one-year term at which time the facilities would be due and payable.

FOURTH QUARTER ANALYSIS

	Q4 2006	Q3 2006	Q4 2005
OPERATIONAL HIGHLIGHTS			
Daily Production			
Natural gas (mcf/d)	88,568	85,701	85,173
Crude oil (bbls/d)	2,030	2,056	2,762
Natural gas liquids (bbls/d)	1,269	1,327	1,355
Total daily production (boe/d)	18,060	17,667	18,312
Average Benchmark Prices			
Natural gas - AECO (daily) (\$/gj)	6.54	5.33	10.72
Natural gas - AECO (monthly) (\$/gj)	6.03	5.72	11.08
Crude oil - WTI (US\$/bbl)	60.21	70.48	60.02
Crude oil - Edmonton par price (Cdn\$/bbl)	64.53	78.83	71.21
Exchange rate (US\$/Cdn\$)	1.1393	1.1212	1.1732
Average Realized Prices			
Natural gas - before hedging (\$/mcf)	7.05	6.28	12.18
Natural gas - after hedging (\$/mcf)	8.35	7.63	11.38
Crude oil (\$/bbl)	59.26	75.69	67.22
Natural gas liquids (\$/bbl)	55.71	68.29	63.63
FINANCIAL HIGHLIGHTS			
(\$ thousands, except per unit amounts)			
Petroleum and natural gas revenue	85,633	82,854	114,167
Royalties	(17,089)	(18,268)	(30,964)
Operating expenses	(11,013)	(10,041)	(9,534)
Transportation expenses	(2,593)	(2,624)	(3,185)
General and administrative expenses	(1,548)	(1,282)	(1,258)
Unit based compensation expense	(1,496)	(1,363)	(1,002)
Cash flow	49,603	47,218	65,785
Depletion, depreciation and accretion	(24,542)	(23,720)	(23,342)
Net earnings	21,538	20,252	29,398
Per unit basic	0.29	0.27	0.41
Per unit diluted	0.28	0.27	0.40
Capital expenditures	35,304	30,875	35,227

Production

Production during the fourth quarter of 2006 of 18,060 boe per day was slightly higher than the third quarter of 2006 of 17,667 boe per day and was slightly lower than the fourth quarter of 2005 at 18,312 boe per day. The production increase from the third quarter to the fourth quarter in 2006 was primarily the result of new wells brought on production during the quarter.

Revenue

Petroleum and natural gas revenue for the fourth quarter of 2006 increased slightly to \$85.6 million compared to the third quarter of 2006 of \$82.9 million and decreased 25 percent from the \$114.2 million recognized for the fourth quarter of 2005. The decrease from the fourth quarter of 2005 is primarily the result of lower natural gas prices.

Royalties

Royalties for the fourth quarter of 2006 decreased six percent to \$17.1 million compared to the third quarter of 2006 of \$18.3 million and decreased 45 percent from the \$31.0 million recognized for the fourth quarter of 2005. The average royalty rate (before the impact of hedging charges) for the fourth quarter of 2006 was approximately 22.8 percent compared to 25.3 percent in the third quarter of 2006 and 25.7 percent in the fourth quarter of 2005. The lower royalty rate in the fourth quarter of 2006 compared to the third quarter of 2006 is due to credits received during the quarter, including marginal well royalty credits. The lower royalty rate in the fourth quarter of 2006 compared to the fourth quarter of 2005 is primarily due to lower natural gas prices.

Operating Expenses

Operating expenses for the fourth quarter of 2006 of \$11.0 million were 10 percent higher than the third quarter of 2006 of \$10.0 million and 16 percent higher than the fourth quarter of 2005 of \$9.5 million. Operating expenses during the fourth quarter of 2006 averaged \$6.63 per boe compared to \$6.18 per boe during the third quarter of 2006 and \$5.66 per boe during the fourth quarter of 2005. The higher operating expenses are the result of additional work performed on the Gold Creek Halfway unit during the fourth quarter.

Transportation Expenses

Transportation expenses for the fourth quarter of 2006 were consistent with the third quarter of 2006 of \$2.6 million and 19 percent lower than the fourth quarter of 2005 of \$3.2 million. The decrease from the fourth quarter of 2005 is due to new reduced tolls negotiated with Spectra Energy in 2006, as well as lower oil production in 2006 which incurs higher transportation costs. Transportation expenses during the fourth quarter of 2006 averaged \$1.56 per boe compared to \$1.61 per boe during the third quarter of 2006 and \$1.89 per boe during the fourth quarter of 2005. Approximately 35 percent of the Trust's production is in British Columbia where there is an infrastructure owned by Spectra Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expenses

G&A expenses for the fourth quarter of 2006 increased 21 percent to \$1.5 million compared to the third quarter of 2006 and the fourth quarter of 2005 of \$1.3 million. The increase over the third quarter of 2006 and the fourth quarter of 2005 is due to the timing of costs incurred as overall G&A costs for the year ended 2006 were six percent below the 2005 expense. G&A expenses averaged \$0.93 per boe during the fourth quarter of 2006 compared to \$0.79 in the third quarter of 2006 and \$0.75 during the fourth quarter of 2005.

Depletion, Depreciation and Accretion

DD&A expense for the fourth quarter of 2006 was \$24.5 million compared to \$23.7 million for the third quarter of 2006 and \$23.3 million for the fourth quarter of 2005. This resulted in DD&A of \$14.77 per boe for the fourth quarter of 2006 compared to \$14.59 per boe for the third quarter of 2006 and \$13.86 for the fourth quarter of 2005. On a boe basis DD&A in 2006 increased due to a higher depletable base in 2006 compared to 2005 including the step-purchase of exchangeable shares upon conversions and asset retirement costs, both of which have no associated reserves.

Income and Capital Taxes

Capital taxes for the fourth quarter of 2006 remained consistent with the third quarter of 2006 of \$0.1 million and lower than the fourth quarter of 2005 of \$0.5 million. The decrease from the fourth quarter of 2005 was due to the federal government eliminating the large corporation tax effective for the 2006 taxation year as part of their June 2006 budget.

The provision for future income taxes in the fourth quarter of 2006 resulted in a recovery of \$1.4 million which was consistent with the third quarter of 2006 and lower than the expense of \$6.6 million in the fourth quarter of 2005. The decrease from the fourth quarter of 2005 is primarily the result of lower earnings in the fourth quarter of 2006 due to lower natural gas prices.

Net Earnings and Cash flow

Net earnings for the fourth quarter of 2006 were \$21.5 million compared to \$20.3 million for the third quarter of 2006 and \$29.4 million for the fourth quarter of 2005. The increase in net earnings over the third quarter of 2006 is due to higher production and natural gas prices while the decrease from the fourth quarter of 2005 is mainly due to lower revenues from lower natural gas prices.

Cash flow for the fourth quarter of 2006 increased five percent to \$49.6 million compared to the third quarter of 2006 of \$47.2 million and decreased 25 percent compared to the fourth quarter of 2005 of \$65.8 million. The decrease from the fourth quarter of 2005 was due to lower natural gas prices.

Capital Expenditures

During the fourth quarter of 2006 the Trust incurred \$35.2 million on exploration and development capital including \$4.3 million in land acquisition and retention, \$0.8 million in geological and geophysical, \$22.1 million in drilling and completions and \$8.0 million in facility construction. During the fourth quarter the Trust drilled 30 gross wells (17.6 net) with 14 gross wells (3.6 net) drilled in the northeast British Columbia Foothills, six gross wells (5.0 net) drilled in the Deep Basin of northwest Alberta, eight gross wells (7.0 net) drilled in central Alberta and two gross wells (two net) drilled in northern Alberta.

Net capital investment during the fourth quarter of 2006 was \$35.3 million compared to \$30.9 million in the third quarter of 2006 and \$35.5 million in the fourth quarter of 2005.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires Management to make judgments and estimates that affect the financial results of the Trust. Progress' Management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 1 to the consolidated financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of Progress' petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Depletion Expense

The Trust uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations

The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

On October 31, 2006 the federal government announced its intention to begin taxing distributions from trusts beginning January 1, 2011. The government also announced its intention to allow trust to corporation conversions to be on a tax-deferred basis (no immediate tax impact) for unitholders. Given these proposed rules have not been substantially enacted into law, there has been no adjustment to future income taxes in regards to this announcement.

CHANGE IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRONOUNCEMENTS

Internal Control Reporting

In March 2006 Canadian Securities Administrators decided to not proceed with proposed multilateral instrument 52-111 Reporting on Internal Control over Financial Reporting and instead proposed to expand multilateral instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The major changes resulting from this is the CEO and CFO will be required to certify in the annual certificates that they have evaluated the effectiveness of internal controls over financial reporting ("ICOFR") as of the end of the financial year and disclose in the annual MD&A their conclusions about the effectiveness of ICOFR. There will be no requirement to obtain an internal control audit opinion from the issuer's auditors concerning management's assessment of the effectiveness of ICOFR. There is also no requirement to design and evaluate internal controls against an external control framework. This proposed amendment is expected to apply for the year ended December 31, 2008. Progress is continuing with its evaluation of ICOFR to ensure it meets the criteria for the proposed certification for December 31, 2008.

Financial Instruments

The following standards regarding financial instruments are effective for January 1, 2007; 3855 – "Financial Instruments – Recognition and Measurement", 3861 Financial Instruments – Disclosure and Presentation, 1530 – "Comprehensive Income", and 3865 – "Hedges". The standards require all financial instruments other than held-to-maturity investments, loans and receivables to be included on a company's balance sheet at their fair value. Held-to-maturity investments, loans and receivables would be measured at their amortized cost. The standards create a new statement for comprehensive income that will include changes in the fair value of certain derivative financial instruments. As a result of these new standards, the Trust expects not to elect to use hedge accounting beginning January 1, 2007 and will record the fair value of its natural gas derivative contracts under its risk management program. The accounting for hedging relationships for prior fiscal years is not retroactively changed, therefore, no restatement of prior periods is expected as a result of these new standards.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

RISK FACTORS AND RISK MANAGEMENT

Investors that purchase trust units are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of Progress' units is subject to numerous risk factors. Some of the risks are common to all businesses while many are associated with the oil and gas industry. The following information is only a summary of certain risk factors which could affect the Trust's future results:

Commodity Price Risk

The Trust's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. With the Trust's production heavily weighted to natural gas, changes to natural gas prices have the most material effect on its cash flow. Prices for natural gas and crude oil have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil producing regions, which are beyond the control of the Trust. Prices received from production in Canada also reflect changes in the Canadian/US currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Trust's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

Progress uses financial derivative instruments in an effort to limit a portion of the potential adverse effects resulting from volatility in natural gas and crude oil commodity prices, while retaining exposure to upside price movements. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase would be foregone.

Operational Matters

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Trust's natural gas and oil properties and assets, as well as possible liability to third parties. The Trust may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of Progress.

Progress employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

Reserve Estimates

Estimates of economically recoverable natural gas and crude oil reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating expenses. All of these estimates may vary from actual results. Estimates of the recoverable natural gas and crude oil reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Trust's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Each year, a firm of independent engineers evaluates a significant portion of proved and probable reserves. At December 31, 2006, 100 percent of the reserves were evaluated by GLJ.

Exploration and Development Risks

Oil and gas exploration and development requires manpower and capital to generate, develop and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves.

Progress attempts to minimize the risk of developing existing and new reserves by ensuring that: (a) the majority of prospects have multi-zone potential (b) activity is focused in core areas where expertise and experience is greatest (c) the number of wells drilled is large enough to increase the probability of statistical success rates (d) geophysical techniques are utilized where appropriate (e) by focusing its activities in core areas and major play types, allowing it to leverage off its experience and knowledge in these areas further aiding efficiencies and (f) farm-outs are entered into to minimize risk on plays it considers higher risk.

Access to Capital Markets

The Trust distributes the majority of its cash flow to unitholders. Access to equity and debt markets may be required for the Trust to finance acquisition and development activity to maintain and grow value to unitholders.

Progress' trust units are listed on the TSX and the Trust maintains an active investor relations program designed to facilitate access to the equity capital markets. Progress also maintains a prudent capital structure by retaining a portion of its net cash flow for debt repayment when appropriate, managing capital expenditures within rate of return risk parameters and by utilizing equity markets.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry, such as the status of mutual fund trusts, will not be changed in a manner which adversely affects the Trust or its unitholders. For example, the tax efficiency of Progress is contingent upon its status as a mutual fund trust under Canadian tax law and therefore may be subject to unanticipated legislative and/or regulator modification.

Although the Trust has no control over these regulatory risks, Progress continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Trust's financial and operating results.

Environment and Safety Risks

The Canadian oil and natural gas industry is subject to environmental and safety regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Trust or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Trust.

The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of unitholders, employees and the public at large. The Trust mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

Credit Risks

The Trust assumes customer credit risk associated with natural gas and crude oil sales, financial hedging transactions and joint venture participants

Management has established controls designed to mitigate the risk of default or non-payment with respect to natural gas and crude oil sales, financial hedging transactions and joint venture participants.

Income Tax Matters

On October 31, 2006 the federal government proposed ("Proposals") to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders. Existing trusts will have a four-year transition period and, subject to the qualification below, will not be subject to the new rules until January 1, 2011. However, assuming the October 31, 2006 Proposals are ultimately enacted in their form, the implementation of such legislation would be expected to result in adverse tax consequences to the Trust and certain unitholders (including most particularly, unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from the Trust.

In light of the foregoing, Management of Progress believes that the October 31, 2006 Proposals may reduce the value of the Trust Units, which would be expected to increase the cost to the Trust of raising capital in the public capital markets. In addition Management of Progress believes that the October 31, 2006 Proposals are expected to: (a) substantially eliminate the competitive advantage that the Trust and other Canadian energy trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner, and (b) place the Trust and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The October 31, 2006 Proposals are also expected to make the trust units less attractive as an acquisition currency. As a result, it may become more difficult for the Trust to compete effectively for acquisition opportunities. There

can be no assurance that the Trust will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the October 31, 2006 Proposals.

Further, the proposals provide that, while there is no intention to prevent “normal growth” during the transitional period, any “undue expansion” could result in the transition period being “revisited”, presumably with the loss of the benefit to the Trust of that transitional period. As a result, the adverse tax consequences resulting from the Proposals could be realized sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by “normal growth” in this context. Specifically, the Department of Finance stated that “normal growth” would include equity growth within certain “safe harbour” limits, measured by reference to a “specified investment flow-through” (“SIFT”) trust’s market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT’s issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance’s guidelines include the following:

- (a) new equity for these purposes includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those);
- (b) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and
- (c) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

The Trust’s market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately \$1,192.1 million, which means the Trust’s “safe harbour” equity growth amount for the period ending December 31, 2007 is approximately \$476.8 million, and for each of calendar 2008, 2009 and 2010 is approximately an additional \$238.4 million (in any case, not including any new equity that may be issued to replace convertible debt outstanding on October 31, 2006).

While these guidelines are such that it is unlikely they would affect the Trust’s ability to raise the capital required to maintain and grow its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust’s ability to undertake more significant acquisitions.

It is not known at this time when the October 31, 2006 Proposals will be enacted by Parliament, if at all, or whether the October 31, 2006 Proposals will be enacted in the form currently proposed. Management continues to monitor the status of the Proposals and analyzing business options should it become law.

Investment Eligibility; Mutual Fund Trust Status

It is intended that the Trust qualify at all times as a mutual fund trust for the purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status, especially in light of the October 31, 2006 Proposals. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- the Units would cease to be a qualified investment for trusts governed by Exempt Plans. Where, at the end of a month, an Exempt Plan holds Units that ceased to be a qualified investment, the Exempt Plan, must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Units at the time such Units were acquired by the Exempt Plan. In addition, trusts governed by a registered retirement savings plan (“RRSP”) or a registered retirement investment fund (“RRIF”) which hold Units that are not qualified investments will be subject to tax on the income attributable to the Units while they are non qualified investments, including the full capital gains, if any, realized on the disposition of such Units. Where a trust governed by a RRSP or a RRIF acquires Units that are not qualified investments, the value of the investment will be included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Units that are not qualified investments can have their registration revoked by the CRA;

- the Trust would be required to pay a tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, including non resident persons and residents of Canada who are exempt from Part I tax;
- the Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws; and
- Units would become taxable Canadian property. As a result, non-resident Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Units held by them.

The Trust may take certain measures in the future to the extent the Trust believes such measures are necessary to ensure the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain unitholders.

OUTLOOK AND 2007 FORECAST

Progress will continue to pursue a disciplined approach to long term sustainability on a per unit basis. Our technical approach and cost control will be primary contributors to sustained value creation for unitholders. Internally generated opportunities will be drilled at a more modest pace than when we were an aggressive growth company. Our inventory of drilling locations currently supports approximately 2 years of activity for Progress while our over 350,000 net acres of undeveloped land provides the opportunity for our technical team to create incremental value.

In creating our Trust, we ensured that we would have access to strong technical and financial staff by having all employees invest in Progress. This creates strong alignment with our unitholders and ensures that we have the professionals to execute our business plan. Employees, Management and Directors hold a 13 percent direct ownership interest in our Trust.

The following table summarizes the Trust's 2007 forecast provided throughout the MD&A. Progress does not forecast commodity prices and as a result, the Trust does not provide a forecast of future cash distributions to unitholders.

<i>2007 Forecast</i>	Target
Average annual production	18,000 to 18,500 boe/d
Royalty rate before hedging charges	26.5 percent
Operating expenses	\$6.00 to \$6.50 per boe
G&A expenses	\$1.00 to \$1.20 per boe
Unit based compensation expenses	\$0.95 per boe
Capital expenditures	\$110 million
Drilling activity	55 to 65 net wells
Pay-out ratio target	50 to 70 percent

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada T2P 4B9 or by e-mail at ir@progressenergy.com. This information is also accessible on the Trust's web site at www.progressenergy.com

REPORT OF MANAGEMENT

The accompanying consolidated financial statements of Progress Energy Trust and all the information in this annual report are the responsibility of Management and have been approved by the Trust's Board of Directors.

The financial statements have been prepared by Management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, Management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Progress Energy Trust maintains appropriate systems of internal accounting and administrative controls of high quality. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed entirely of independent directors, meets regularly with Management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy and financial reporting matters. The Committee reviews the financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors. The Committee also considers, for review by the Board and approval by the unitholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by KPMG LLP, the external auditors, in accordance with Canadian generally accepted auditing standards on behalf of the unitholders. KPMG LLP has full and free access to the Audit Committee.

(signed) "*Michael R. Culbert*"
President and CEO
Progress Energy Ltd.

(signed) "*Art A. MacNichol*"
Vice President, Finance and CFO
Progress Energy Ltd.

February 26, 2007

AUDITORS' REPORT

To the Unitholders of Progress Energy Trust

We have audited the consolidated balance sheets of Progress Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of earnings and deficit and cash flows for the years ended December 31, 2006 and 2005. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years ended December 31, 2006 and 2005 in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
February 26, 2007

(signed) "KPMG LLP"
Chartered Accountants

PROGRESS ENERGY TRUST **CONSOLIDATED BALANCE SHEETS**

<i>As at December 31 (\$ thousand)</i>	2006	2005
ASSETS		
Current		
Cash and short-term investments	8,265	-
Accounts receivable	35,555	45,870
Prepaid expenses and deposits	7,798	5,144
	51,618	51,014
Property, plant and equipment (Note 2)	744,431	687,316
Goodwill	414,655	414,655
	1,210,704	1,152,985
LIABILITIES		
Current		
Accounts payable and accrued liabilities	49,820	58,904
Cash distributions payable	10,564	9,982
Current income taxes payable	5,193	5,001
	65,577	73,887
Bank debt (Note 3)	75,000	71,326
Convertible debentures (Note 4)	119,605	79,381
Commodity sales contract (Note 10)	876	1,446
Asset retirement obligations (Note 5)	24,148	20,906
Future income taxes (Note 8)	114,367	124,186
	399,573	371,132
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 6)	122,592	127,205
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 7)	739,998	681,263
Convertible debentures (Note 4)	7,702	4,261
Contributed surplus (Note 7)	9,210	3,530
Deficit	(68,371)	(34,406)
	688,539	654,648
Commitments (Note 11)		
	1,210,704	1,152,985

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board

(signed) "David D. Johnson"
Director

(signed) "Donald F. Archibald"
Director

PROGRESS ENERGY TRUST
CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT

<i>Year ended December 31 (\$ thousands, except per unit amounts)</i>	2006	2005
REVENUE		
Petroleum and natural gas	340,455	369,768
Royalties	(78,762)	(94,492)
	261,693	275,276
EXPENSES		
Operating	40,353	37,170
Transportation	11,017	12,578
General and administrative	6,321	6,746
Unit based compensation (Note 7)	4,874	3,029
Interest and financing	11,798	10,589
Depletion, depreciation and accretion	94,708	92,040
	169,071	162,152
Earnings before taxes and non-controlling interest	92,622	113,124
TAXES		
Capital taxes	180	2,172
Future income taxes (Note 8)	(14,673)	4,067
	(14,493)	6,239
Net earnings before non-controlling interest	107,115	106,885
Non-controlling interest – exchangeable shares (Note 6)	15,517	17,961
NET EARNINGS	91,598	88,924
Deficit, beginning of year	(34,406)	(6,870)
Distributions	(125,563)	(116,460)
Deficit, end of year	(68,371)	(34,406)
NET EARNINGS PER UNIT (Note 7)		
Basic	\$ 1.23	\$ 1.29
Diluted	\$ 1.21	\$ 1.27

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST **CONSOLIDATED STATEMENTS OF CASH FLOWS**

<i>Year ended December 31 (\$ thousands)</i>	2006	2005
Operating Activities		
Net earnings	91,598	88,924
Depletion, depreciation and accretion	94,708	92,040
Non-controlling interest – exchangeable shares <i>(Note 6)</i>	15,517	17,961
Convertible debentures accretion <i>(Note 4)</i>	872	793
Amortization of convertible debenture issue costs <i>(Note 4)</i>	717	755
Amortization of commodity sales contract <i>(Note 10)</i>	(570)	(648)
Unit based compensation expense <i>(Note 7)</i>	4,874	3,029
Asset retirement expenditures <i>(Note 5)</i>	(2,714)	(944)
Future income taxes	(14,673)	4,067
	190,329	205,977
Changes in non-cash working capital <i>(Note 9)</i>	(170)	(14,886)
	190,159	191,091
Financing Activities		
Increase (decrease) in bank debt	3,674	(62,396)
Issue of convertible debentures <i>(Note 4)</i>	75,000	100,000
Convertible debenture issue costs <i>(Note 4)</i>	(3,306)	(4,515)
Cash distributions	(124,981)	(115,843)
Changes in non-cash working capital <i>(Note 9)</i>	-	-
	(49,613)	(82,754)
Investing Activities		
Capital expenditures	(134,652)	(107,658)
Change in non-cash working capital <i>(Note 9)</i>	2,371	(679)
	(132,281)	(108,337)
Change in cash and short-term investments	8,265	-
Cash and short-term investments, beginning of year	-	-
Cash and short-term investments, end of year	8,265	-

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts are in \$ thousands except for trust units and per trust unit amounts)

Progress Energy Trust (“Progress” or the “Trust”) is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and royalty interests in petroleum and natural gas properties. Progress Energy Ltd. carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust owns, directly and indirectly, 100 percent of the common shares (excluding the exchangeable shares – see note 6) of Progress Energy Ltd. The activities of Progress Energy Ltd. are financed through interest bearing notes from the Trust and third party debt. The convertible debentures are direct obligations of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust, which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest (“NPI”) agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow from operations before changes in non-cash working capital each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Pursuant to the terms of the NPI agreement, the Trust is entitled to a payment from Progress Energy Ltd. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed 99% of certain deductible expenditures (as defined). Under the terms of the NPI agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of Progress Energy Ltd.

Relationship with ProEx

A technical services agreement (“Technical Services Agreement”) is currently in place between the Trust and ProEx Energy Ltd. (“ProEx”) whereby the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. ProEx has granted performance shares to the employees of Progress as service providers. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expense reimbursed by ProEx for the year ended December 31, 2006 was \$4.5 million (2005 - \$2.8 million).

The Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition, the Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

As at December 31, 2006, accounts payable included \$4.6 million (2005 - \$1.8 million) payable to ProEx which includes standard joint venture amounts including revenue. These amounts were paid subsequent to year end.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

The Trust is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Trust only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the asset retirement obligations and related accretion are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Trust uses the full cost method of accounting for petroleum and natural gas properties under which all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

In accordance with the full cost accounting guideline, the Trust evaluates its oil and gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved plus probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated proven reserves of petroleum and natural gas on a Trust interest basis (working interest plus royalty interest) before the deduction of crown and other royalties as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil.

Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Other assets, which is comprised of office equipment and furniture and fixtures, is recorded at cost and are depreciated over their useful life on a declining balance basis at 20 percent.

Asset Retirement Obligations

The Trust records a liability for the fair value of future asset retirement obligations in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset within property, plant and equipment, which is depleted on a unit-of-production basis over the life of the reserves. Estimates used are evaluated on a periodic basis and any adjustments are applied prospectively. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

Goodwill

Goodwill is recognized on corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets of the acquired company. Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value.

Financial Instruments

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Trust may enter into crude oil and natural gas swap contracts, options or collars to hedge its exposure to petroleum and natural gas commodity prices and may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar denominated petroleum and natural gas sales. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy and the Trust does not enter into derivative financial instruments for trading or speculative purposes.

The Trust designates its derivative financial instruments as hedges and performs the necessary procedures to enable the use of hedge accounting. This includes the formal documentation of the hedge, linking all derivatives to specific assets and liabilities on the balance sheet or specific firm commitments or forecasted transactions and performing assessments of hedge effectiveness. Derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

Financial instruments that do not qualify for hedge accounting or are not designated as hedges are recorded at their fair value on the balance sheet with changes in the fair value recognized in earnings.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made for the Trust. The future income tax liability on the consolidated balance sheet represents the future income tax liability of the Trust's subsidiary.

On October 31, 2006 the federal government announced its intention to begin taxing distributions from trusts beginning January 1, 2011. The government has also proposed to limit the growth of existing trusts by limiting new equity issues to 40 percent of that trust's October 31, 2006 market capitalization ("benchmark") for 2007, and an additional 20 percent of the benchmark for each of 2008, 2009 and 2010. For Progress, the limits would be \$476.8 million for 2007 and \$238.4 million for each of 2008, 2009 and 2010 with any unused balance rolling forward to the following year. The government also announced its intention to allow trust to corporation conversions to occur on a tax-deferred basis (no

immediate tax impact) for unitholders. Given these proposed rules have not been substantially enacted into law, there has been no adjustment to future income taxes in regards to this announcement.

Unit Based Compensation

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary. The Trust uses the fair value method for valuing unit based compensation and unit option grants. Under this method, compensation cost attributed to performance units granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the settlement of the Plan, the previously recognized value in contributed surplus will be recorded as an increase to unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for performance units that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

Per Unit Information

Per unit information is calculated on the basis of the weighted average number of trust units outstanding during the fiscal year. Diluted per unit information includes the impact of the issuable exchangeable shares, as well as, the potential dilution that could occur if securities or other contracts to issue units were exercised or converted to units. Diluted per unit information is calculated using the treasury stock method that assumes any proceeds received by the Trust upon the exercise of in-the-money unit options plus the unamortized unit compensation cost would be used to buy back trust units at the average market price for the period.

Exchangeable Securities – Non-Controlling Interest

The Trust accounts for outstanding exchangeable shares as non-controlling interest given exchangeable shareholders can dispose of their shares without having to exchange them for trust units. The exchangeable shares of the Trust's subsidiary trade on the Toronto Stock Exchange. As a result, the exchangeable shares have been classified as non-controlling interest on the consolidated balance sheet outside of unitholders' equity. Net earnings attributable to the exchangeable shares is charged to the consolidated statement of earnings as non-controlling interest expense with a corresponding increase to non-controlling interest on the consolidated balance sheet.

Each redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders is accounted for as a step-purchase resulting in an increase to property, plant and equipment, an increase to unitholders' capital and an increase in the Trust's future income tax liability. The non-controlling interest activity for the years ended December 31, 2006 and 2005 is disclosed in note 6.

2. PROPERTY, PLANT AND EQUIPMENT

	2006	2005
Property, plant and equipment	1,001,785	865,173
Conversion of exchangeable shares	46,014	32,553
Accumulated depletion and depreciation	(303,368)	(210,410)
Property, plant and equipment, net	744,431	687,316

As described in note 1, the redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders are accounted for as a step-purchase. Consequently, a charge of \$13.5 million was made to property, plant and equipment for the year ended December 31, 2006 (2005 - \$22.2 million).

In June 2006, the Trust disposed of its assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at \$1.20 per share for a total consideration of \$3.4 million.

The calculation of 2006 depletion and depreciation included an estimated \$34.5 million (2005 - \$26.9 million) for future development costs associated with proved undeveloped reserves and excluded \$24.0 million (2005 - \$24.0 million) for the estimated future net realizable value of production equipment and facilities and \$58.2 million (2005 - \$65.7 million) for the estimated value of unproven properties. Depletion and depreciation expense for the year ended December 31, 2006 was \$93.0 million (2005 - \$90.6 million).

Included in the Trust's property, plant and equipment balance is \$14.8 million (2005 - \$12.5 million), net of accumulated depletion, related to asset retirement obligations (\$22.9 million before accumulated depletion (2005 - \$18.7 million)) (Refer to note 5).

The Trust capitalized approximately \$1.2 million of geological and geophysical expenses associated with the exploration and development of capital assets during the year ended December 31, 2006 (2005 - \$1.4 million).

The Trust performed a ceiling test calculation at December 31, 2006 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Trust used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas	Edmonton Par	AECO Gas price
	Intermediate(1)	Price	
	(Cdn\$/bbl)	(Cdn\$/bbl)	(Cdn\$/mmbtu)
2007	71.26	70.25	7.20
2008	68.97	68.00	7.45
2009	66.67	65.75	7.75
2010	65.52	64.50	7.80
2011	65.52	64.50	7.85
2012-2017(2)	69.44	68.38	8.61
Thereafter(3)	2.0%	2.0%	2.0%

(1) Future prices incorporated a 0.87 US/Cdn exchange rate.

(2) Prices shown are the average over the period.

(3) Percentage change of 2.0% represents the change in future prices each year after 2017 to the end of the reserve life.

3. BANK DEBT

	2006	2005
Direct advances	-	1,326
Banker's acceptances	75,000	70,000
Total bank debt	75,000	71,326

The Trust's credit facilities totaling \$215 million are with a syndicate of banks consisting of a \$200 million extendible revolving term credit facility and a \$15 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 29, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. Various borrowing options are available under the facilities including prime rate based advances and banker's acceptance loans. Average cost of borrowing under these facilities for the year ended December 31, 2006 was 5.1 percent (2005 - 4.2 percent). The credit facilities are secured by a \$500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress in respect of the Trust's obligations. The \$215 million borrowing base is subject to semi-annual review by the banks.

4. CONVERTIBLE DEBENTURES

On August 22, 2006 the Trust issued \$75 million principal amount of 6.25 percent convertible unsecured subordinated debentures (the "6.25 percent debentures") for net proceeds of \$71.7 million. The 6.25 percent debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011, at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

On February 2, 2005 the Trust issued \$100 million principal amount of 6.75 percent convertible unsecured subordinated debentures (the "6.75 percent debentures") for net proceeds of \$95.5 million. The 6.75 percent debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$15.00 per trust unit. The 6.75 percent debentures mature on June 30, 2010 at which time they are due and payable. The

Trust may elect to satisfy the interest and principal obligations by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.25 percent debentures and the 6.75 percent debentures (the “Debentures”) have been classified as debt, net of issue costs and net of the fair value of the conversion feature at the date of issue which has been classified as part of unitholders’ equity. The issue costs will be amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings. If the Debentures are converted to units, a portion of the value of the conversion feature under unitholders’ equity will be reclassified to unitholders’ capital along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

	2006			2005		
	6.75%	6.25%	Total	6.75%	6.25%	Total
Principal, beginning of year(1)	86,182	75,000	161,182	100,000	-	100,000
Converted to trust units	(30,455)	-	(30,455)	(13,818)	-	(13,818)
Principal, end of year	55,727	75,000	130,727	86,182	-	86,182
Debt portion, beginning of year(1)	79,381	66,748	146,129	90,541	-	90,541
Accretion	535	337	872	793	-	793
Amortization of issue costs	497	220	717	755	-	755
Conversions to trust units(2)	(28,113)	-	(28,113)	(12,708)	-	(12,708)
Debt portion, end of year	52,300	67,305	119,605	79,381	-	79,381
Equity portion, beginning of year(1)	4,261	4,946	9,207	4,944	-	4,944
Conversions to trust units	(1,505)	-	(1,505)	(683)	-	(683)
Equity portion, end of year	2,756	4,946	7,702	4,261	-	4,261

(1) The 6.75 percent debentures were issued February 2, 2005 and the 6.25 percent debentures were issued August 22, 2006.

(2) Net of unamortized issue costs.

Total interest charged to earnings for the year ended December 31, 2006 was \$7.4 million (2005 – \$7.6 million) which includes \$0.9 million of debenture accretion (2005 – \$0.8 million) and \$0.7 million of amortized issue costs (2005 – \$0.8 million).

5. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations were estimated based on the Trust’s net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately \$56.7 million which will be incurred over the next 41 years with the majority of costs incurred between 2009 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations. In 2005, the Trust increased the inflation rate used to calculate the obligations from 1.5 percent to 2.0 percent and revised its estimate for abandonment and reclamation costs in certain areas. The impact of these revised estimates was an increase to the liability of \$1.7 million.

The following reconciles the Trust’s asset retirement obligations:

	2006	2005
Balance, beginning of year	20,906	16,065
Liabilities incurred	4,580	2,651
Liabilities settled	(2,714)	(944)
Dispositions	(374)	-
Change in estimates	-	1,687
Accretion expense	1,750	1,447
Balance, end of year	24,148	20,906

6. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares issued to Progress Energy Ltd. shareholders and the fair value of exchangeable shares issued to Cequel Energy Inc. shareholders as part of a Plan of Arrangement that became effective on July 2, 2004, plus net earnings attributable to the exchangeable shares, less exchangeable shares (and related cumulative earnings) redeemed. The non-controlling interest charge on the consolidated statement of earnings represents the share of net earnings attributable to the exchangeable shares based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end. The activity for non-controlling interest for the year ended December 31, 2006 and 2005 is as follows:

Exchangeable shares	2006		2005	
	Number	Amount	Number	Amount
Balance, beginning of year	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,746,211)	(20,130)	(3,144,755)	(31,816)
Non-controlling interest expense		15,517		17,961
Balance, end of year	9,642,540	122,592	11,388,751	127,205

The exchangeable shares can be converted, at the option of the holder, into trust units at any time and are listed on the Toronto Stock Exchange under the symbol PGE. If the number of exchangeable shares outstanding is less than 1,600,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions.

Retraction of Exchangeable Shares

Exchangeable shareholders may redeem their shares at any time by delivering their share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On July 2, 2009 the exchangeable shares will be redeemed by the Trust unless the Board of Directors of Progress Energy Ltd. elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units or payment in cash for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

7. UNITHOLDERS' CAPITAL

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

Trust Units	2006		2005	
	Number	Amount	Number	Amount
Balance, beginning of year	71,302,265	681,263	66,898,498	621,490
Exchangeable shares converted	2,124,705	29,117	3,482,575	46,382
Issued on conversion of Debentures	2,030,321	29,618	921,192	13,391
Balance, end of year	75,457,291	739,998	71,302,265	681,263

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum of \$250,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 90 percent of the simple average closing price of the trust units on the principal market on which they are traded for the 10 day trading period after the trust units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the last bid and ask prices of the trust units on that date.

Net Earnings Per Unit

The following table summarizes the weighted average trust units used in calculating net earnings per unit:

	2006	2005
Weighted average trust units – basic	74,536,584	69,117,770
Trust units issuable on conversion of exchangeable shares(1)	13,267,333	14,934,133
Performance units	477,461	151,561
Weighted average trust units – diluted	88,281,378	84,203,464

(1) Calculated based on the weighted average exchangeable shares outstanding during the year at the year end exchange ratio.

An adjustment to the numerator of \$15.5 million for the year ended December 31, 2006 (2005 – \$18.0 million) is required in the diluted earnings per unit calculation to provide for earnings attributable to non-controlling interest.

Units potentially issuable on the conversion of the Debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the years ended December 31, 2006 and 2005.

Performance Unit Incentive Plan

The Trust has established a Performance Unit Incentive Plan (the “Plan”) for employees and directors of the Trust or its subsidiary. The number of units reserved for issuance under the Plan shall not exceed 5 percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares, which may be converted into trust units. Under the Plan, performance units shall be granted by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial performance units granted. Over the three year term the performance units will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

As at December 31, 2006 there are 380,567 performance units outstanding that were granted effective July 2, 2004. As a result, the fair value of the performance units granted, calculated using a performance factor of 1.0, is approximately \$5.1 million of which \$4.5 million will be amortized through unit based compensation expense and \$0.6 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

As at December 31, 2006 there are 512,300 performance units outstanding that were granted effective July 2, 2005. The fair value of the performance units using a performance factor of 1.0 is approximately \$8.1 million of which \$7.0 million will be amortized through unit based compensation expense and \$1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

As at December 31, 2006 there are 407,850 performance units outstanding that were granted effective July 2, 2006. The fair value of the performance units using a performance factor of 1.0 is approximately \$6.5 million of which \$5.6 million will be amortized through unit based compensation expense and \$0.9 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the year ended December 31, 2006 \$4.9 million (2005 – \$3.0 million) was charged to unit based compensation expense and \$0.8 million (2005 – \$0.3 million) was capitalized relating to the total performance units outstanding.

	2006	2005
Performance Units		
Balance, beginning of year	899,567	395,267
Granted	424,950	511,500
Forfeited	(23,800)	(7,200)
Balance, end of year	1,300,717	899,567
Vesting Date		
July 2, 2007	380,567	388,067
July 2, 2008	512,300	511,500
July 2, 2009	407,850	-
Total	1,300,717	899,567

Contributed Surplus

The following table reconciles the Trust's contributed surplus:

	2006	2005
Balance, beginning of year	3,530	171
Unit based compensation expense	4,874	3,029
Unit based compensation capitalized	806	330
Balance, end of year	9,210	3,530

8. FUTURE INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. Cash distributions for the year ended December 31, 2006 totaled \$125.6 million (2005 – \$116.5 million), reducing the Trust's expected future income tax expense for the year.

Included in the 2006 provision is a recovery of \$9.2 million relating to a reduction in future federal and provincial tax rates enacted during the year and the impact of certain tax balance adjustments.

During 2005, income tax audits were performed on the 2002 and 2003 tax returns of Cequel and Progress Energy Ltd. As a result of these audits, the provision for future income tax expense for 2005 includes a charge of \$3.5 million due to tax pool adjustments.

The combined provision for taxes in the consolidated statements of earnings and deficit reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

	2006	2005
Earnings before taxes	92,622	113,124
Statutory income tax rate	34.8%	37.9%
Expected income taxes	32,232	42,874
Add (deduct)		
Net income of the Trust	(39,660)	(43,366)
Non-deductible crown charges	7,940	20,271
Resource allowance	(7,470)	(17,083)
Reduction in income tax rates and certain tax balance adjustments	(9,212)	(2,003)
Income tax audit adjustments	129	3,495
Attributed Canadian Royalty Income	(216)	(886)
Other	1,584	765
	(14,673)	4,067

The future income taxes liability at December 31 is comprised of the tax effect of temporary differences as follows:

	2006	2005
Property, plant and equipment	124,460	135,120
Asset retirement obligations	(7,268)	(7,060)
Commodity sales contracts	(260)	(488)
Share issue costs	(138)	(629)
Attributed Canadian Royalty Income	(2,427)	(2,757)
	114,367	124,186

As at December 31, 2006, the Trust's corporate subsidiary, Progress Energy Ltd., has federal tax pools of approximately \$268.0 million (2005 - \$225.0 million) available for deduction against future taxable income. The Trust currently has tax pools available of \$85.0 million compared to their related carrying amounts on the balance sheet of \$67.4 million, resulting in temporary differences in a net asset position of \$17.6 million (2005 - \$8.8 million) for which no future tax has been recorded.

The following are the combined tax pools available for the Trust and its corporate subsidiary:

	2006
Canadian exploration expense	80,000
Canadian development expense	80,000
Canadian oil and gas property expense	92,000
Undepreciated capital cost	93,000
Non-capital losses	1,000
Share issue costs	7,000
Attributed Canadian Royalty Income	29,000

9. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	2006	2005
Accounts receivable	10,315	(15,007)
Prepaid expenses and deposits	778	(774)
Accounts payables	(9,084)	1,924
Current income taxes payable	192	(1,708)
Change in non-cash working capital	2,201	(15,565)
Relating to:		
Financing activities	-	-
Investing activities	2,371	(679)
Operating activities	(170)	(14,886)

Interest and taxes paid

	2006	2005
Interest paid	8,641	6,220
Income and other taxes paid	182	3,366

10. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Trust's financial instruments recognized on the balance sheet consist of accounts receivable, accounts payable and accrued liabilities, bank debt and convertible debentures. The fair value of these financial instruments, excluding the convertible debentures, approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt. The fair value of the Debentures outstanding as at December 31, 2006 was approximately \$130.2 million.

Credit Risk

The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. The Trust routinely assesses the financial strength of its customers.

The Trust may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Trust mitigates this risk by entering into transactions with highly rated major financial institutions.

Commodity Price Contracts

The Trust has entered into several derivative financial instruments for the purpose of protecting its cash flow from operations before changes in non-cash working capital from the volatility of natural gas prices. For the year ended December 31, 2006, the Trust's natural gas price risk management program had a net gain of \$29.9 million (2005 - \$5.7 million net loss) which is included in petroleum and natural gas revenue on the statements of earnings.

Contracts outstanding in respect to financial instruments are as follows:

Natural Gas Contracts(1)	Pricing		Strike Price \$/gj	Cost/		Term
	Volume	Point		Premium		
Swap - call spread	10,000 gj/d	AECO	\$9.51 - \$10.51	\$0.44/gj		Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$ 8.97 - \$9.97	\$0.38/gj		Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$9.60 - \$10.60	\$0.40/gj		Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$9.63 - \$10.63	\$0.43/gj		Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$ 7.45 - \$8.45	\$0.42/gj		Apr 01/07 - Oct 31/07
Swap - call spread	10,000 gj/d	AECO	\$ 7.41 - \$8.41	\$0.39/gj		Apr 01/07 - Oct 31/07
Swap - call spread	10,000 gj/d	AECO	\$ 7.42 - \$8.42	\$0.37/gj		Apr 01/07 - Oct 31/07
Swap - call spread	10,000 gj/d	AECO	\$ 7.43 - \$8.43	\$0.38/gj		Apr 01/07 - Oct 31/07

(1) Costless collar and call spread strike prices indicate minimum floor and maximum ceiling

The estimated fair value of the natural gas financial instruments that qualify for hedge accounting was a gain of \$14.0 million as at December 31, 2006 and represents the amount the Trust would receive to terminate the contracts at December 31, 2006. These instruments have no carrying value recorded in the financial statements.

Commodity Sales Contract

The following physical gas sales contract was outstanding at December 31, 2006. This contract was acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002, at which time the fair value of the contracts was a liability of \$4.1 million. This value was recorded as a liability on June 3, 2002, and is being amortized over the life of the contract. At December 31, 2006 the unamortized liability remaining was \$0.9 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	\$2.16/gj in 2007 escalating at 2.5% annually	Jun 1/97 – Oct 31/08

11. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts, drilling rig agreements, compressor rentals and office space. Payments required under these commitments for each of the next five years are: 2007 - \$17.7 million; 2008 - \$10.9 million; 2009 - \$7.5 million; 2010 - \$5.0 million; 2011 - \$3.5 million and thereafter nil. Future commitments related to bank debt and the Debentures are disclosed in notes 3 and 4, respectively.

2006 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS <i>(\$ thousands except per unit amounts)</i>	Three Months Ended 2006				Annual
	March 31	June 30	Sept. 30	Dec. 31	2006
Income Statement					
Petroleum and natural gas revenue	90,959	81,009	82,854	85,633	340,455
Cash flow(1)	47,637	45,871	47,218	49,603	190,329
Per unit – diluted	0.55	0.52	0.54	0.56	2.16
Cash distributions declared	30,836	31,412	31,626	31,689	125,563
Per unit	0.42	0.42	0.42	0.42	1.68
Net earnings	21,383	28,425	20,252	21,538	91,598
Per unit – basic	0.29	0.38	0.27	0.29	1.23
Per unit – diluted	0.29	0.38	0.27	0.28	1.21
Payout Ratio					
Excluding exchangeable shares	65%	68%	67%	64%	66%
Including exchangeable shares	76%	80%	78%	75%	78%
Balance Sheet					
Capital Expenditures	35,984	32,489	30,875	35,304	134,652
Total debt	172,106	182,873	190,531	208,564	208,564
Unitholders' equity	687,953	694,236	696,844	688,539	688,539
Trust Units (thousands except where otherwise stated)					
Units outstanding, end of period	74,315	74,901	75,448	75,457	75,457
Units issuable for exchangeable shares	12,309	12,314	12,301	12,657	12,657
Total units outstanding and issuable for exchangeable shares, end of period	86,624	87,215	87,749	88,114	88,114
Weighted average units – diluted(2)	86,579	87,557	88,190	88,623	88,281
Exchange ratio, end of period	1.21322	1.24284	1.27469	1.31263	1.31263
Trust Unit Trading Statistics (\$)					
High	18.20	18.33	17.50	16.21	18.33
Low	14.75	14.73	14.21	10.60	10.60
Closing	17.45	16.30	15.30	12.57	12.57
Unit volume traded (thousands)	18,619	12,619	15,524	23,725	279,051
Exchangeable Shares Trading Statistics (\$)					
High	21.29	21.76	22.48	20.40	22.48
Low	18.49	18.28	18.60	14.90	14.90
Closing	20.70	19.57	18.60	16.21	16.21
Share volume traded (thousands)	85	15	69	31	200

(1) See discussion in the Management Discussion and Analysis

(2) Includes exchangeable shares converted at the end of period exchange ratio.

2006 SELECTED QUARTERLY INFORMATION

Operational Highlights	Three Months Ended 2006				Annual
	March 31	June 30	Sept. 30	Dec. 31	2006
Daily Production					
Natural gas (mcf/d)	86,433	82,271	85,701	88,568	85,749
Crude oil (bbls/d)	2,605	2,099	2,056	2,030	2,196
Natural gas liquids (bbls/d)	1,390	1,478	1,327	1,269	1,366
Total daily production (boe/d)	18,401	17,288	17,667	18,060	17,853
Average Realized Prices					
Natural gas - before hedging (\$/mcf)	8.80	6.53	6.28	7.05	7.17
Natural gas - after hedging (\$/mcf)	8.74	7.83	7.63	8.35	8.14
Crude oil (\$/bbl)	64.45	72.79	75.69	59.26	67.88
Natural gas liquids (\$/bbl)	62.86	63.34	68.29	55.71	62.65
Highlights (\$/boe)					
Weighted average sales price	54.92	51.49	50.97	51.54	52.25
Royalties	14.87	11.94	11.24	10.29	12.09
Operating expenses	5.81	6.15	6.18	6.63	6.19
Transportation expenses	1.91	1.68	1.61	1.56	1.69
Operating Netbacks	32.33	31.72	31.94	33.06	32.28
General and administrative expense	1.08	1.08	0.79	0.93	0.97
Unit based compensation	0.61	0.64	0.84	0.90	0.75
Interest and financing expenses	1.45	1.60	2.02	2.16	1.81
Depletion, depreciation and accretion	14.27	14.49	14.59	14.77	14.53
Net earnings before taxes	14.92	13.91	13.70	14.30	14.22
Capital taxes	0.20	(0.16)	0.03	0.03	0.03
Future income taxes (recovery)	(0.56)	(6.98)	(0.83)	(0.85)	(2.25)
Non-controlling interest - exchangeable shares	2.37	2.98	2.04	2.16	2.38
Net Earnings	12.91	18.07	12.46	12.96	14.06
Drilling Results					
Gross	39	15	22	30	106
Net - natural gas	19.3	11.0	9.8	15.6	55.7
Net - crude oil	0.8	0.4	1.6	2.0	4.7
Success Rate (percent)	93	100	95	100	97

2005 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS <i>(\$ thousands except per unit amounts)</i>	Three Months Ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Income Statement					
Petroleum and natural gas revenue	79,007	83,222	93,372	114,167	369,768
Cash flow(1)	42,511	44,466	53,215	65,785	205,977
Per unit – diluted	0.52	0.53	0.63	0.77	2.45
Cash distributions declared	28,574	28,874	29,210	29,802	116,460
Per unit	0.42	0.42	0.42	0.42	1.68
Net earnings	17,527	16,840	25,159	29,398	88,924
Per unit – basic	0.27	0.25	0.36	0.41	1.29
Per unit – diluted	0.27	0.24	0.36	0.40	1.27
Payout Ratio					
Excluding exchangeable shares	67%	65%	55%	45%	57%
Including exchangeable shares	81%	79%	66%	54%	69%
Balance Sheet					
Capital Expenditures	34,380	13,559	24,492	35,227	107,658
Total debt	187,312	185,708	186,115	173,580	173,580
Unitholders' equity	632,700	623,308	635,630	654,648	654,648
Trust Units (thousands except where otherwise stated)					
Units outstanding, end of period	68,646	68,820	69,956	71,302	71,302
Units issuable for exchangeable shares	13,992	14,281	13,601	13,482	13,482
Total units outstanding and issuable for exchangeable shares, end of period	82,638	83,101	83,557	84,784	84,784
Weighted average units – diluted(2)	82,485	83,176	83,700	84,675	84,203
Exchange ratio, end of period	1.08438	1.12038	1.15421	1.18384	1.18384
Trust Unit Trading Statistics (\$)					
High	14.50	13.79	17.82	17.85	17.85
Low	12.52	11.90	13.07	14.08	11.90
Closing	13.38	13.03	17.61	17.17	17.17
Unit volume traded (thousands)	17,788	11,544	19,159	18,385	66,876
Exchangeable Shares Trading Statistics (\$)					
High	15.85	15.50	20.62	20.36	20.62
Low	13.96	13.27	15.00	16.61	13.27
Closing	14.60	14.96	19.26	20.36	20.36
Share volume traded (thousands)	1,460	290	613	52	2,415

(1) See discussion in the Management Discussion and Analysis

(2) Includes exchangeable shares converted at the end of period exchange ratio.

2005 SELECTED QUARTERLY INFORMATION

Operational Highlights	Three Months Ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Daily Production					
Natural gas (mcf/d)	84,523	79,236	80,804	85,173	82,431
Crude oil (bbls/d)	2,550	3,067	2,734	2,762	2,779
Natural gas liquids (bbls/d)	1,598	1,305	1,280	1,355	1,384
Total daily production (boe/d)	18,235	17,578	17,481	18,312	17,901
Average Realized Prices					
Natural gas – before hedging (\$/mcf)	7.31	8.12	9.33	12.18	9.27
Natural gas – after hedging (\$/mcf)	7.69	8.13	9.11	11.38	9.11
Crude oil (\$/bbl)	59.44	64.20	72.66	67.22	65.98
Natural gas liquids (\$/bbl)	47.82	56.41	62.68	63.63	57.20
Highlights (\$/boe)					
Weighted average sales price	48.14	52.02	58.06	67.77	56.59
Royalties	11.78	13.16	14.39	18.38	14.46
Operating expenses	5.69	5.72	5.70	5.66	5.69
Transportation expenses	1.89	1.98	1.95	1.89	1.93
Operating Netbacks	28.78	31.16	36.02	41.84	34.51
General and administrative expense	1.23	1.33	0.83	0.75	1.03
Unit based compensation	0.31	0.32	0.62	0.59	0.46
Interest and financing expenses	1.26	1.80	1.80	1.62	1.62
Depletion, depreciation and accretion	14.05	14.19	14.26	13.86	14.09
Net earnings before taxes	11.93	13.52	18.51	25.02	17.31
Capital taxes	0.33	0.34	0.34	0.32	0.33
Future income taxes (recovery)	(1.48)	0.55	(0.63)	3.93	0.62
Non-controlling interest – exchangeable shares	2.40	2.10	3.16	3.32	2.75
Net Earnings	10.68	10.53	15.64	17.45	13.61
Drilling Results					
Gross	25	8	24	31	88
Net – natural gas	8.4	2.7	9.7	16.0	36.8
Net – crude oil	2.6	0.0	1.9	1.7	6.2
Success Rate (percent)	86	60	89	100	90

CORPORATE INFORMATION

DIRECTORS

David D. Johnson
Chairman
Progress Energy Ltd.
President & CEO
ProEx Energy Ltd.
Calgary, Alberta

Donald F. Archibald(1)(4)(5)
Chairman & CEO
Cyries Energy Inc.
Calgary, Alberta

John A. Brussa(3)(5)
Partner
Burnet, Duckworth and Palmer LLP
Calgary, Alberta

Frederic C. Coles(1)(2)(4)(5)
Independent Businessman
Calgary, Alberta

Howard Crone(1)(2)(4)(5)
Independent Businessman
Calgary, Alberta

Michael R. Culbert
President and CEO
Progress Energy Ltd.
Calgary, Alberta

Gary E. Perron(1)(3)(5)
Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

- (1) Member of Audit Committee
 - (2) Member of Reserve Committee
 - (3) Member of Compensation Committee
 - (4) Member of Technical Services Committee
 - (5) Member of Corporate Governance and Nominating Committee
- Environment, Health and Safety matters are addressed by the entire Board of Directors

OFFICERS

David D. Johnson
Chairman

Michael R. Culbert
President and CEO

Steven A. Allaire
Senior Vice President

Greg W. Kist
Vice President Investor
Relations and Marketing

Art A. MacNichol
Vice President Finance &
Chief Financial Officer

Cindy R. Rutherford
Vice President Land

Neil H. Samis
Vice President Production

Daniel C. Topolinsky
Vice President Exploration

Gary R. Bugeaud
Secretary

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TRUSTEE AND TRANSFER AGENT

Computershare Trust Company
of Canada
Calgary, Alberta

STOCK EXCHANGE

The Toronto Stock Exchange
trading symbols:
Trust Units – PGX.UN
Exchangeable Shares – PGE
6.75% Debentures – PGX.DB
6.25% Debentures – PGX.DB.A

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR

KPMG LLP
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CONSULTING ENGINEERS

GLJ Petroleum Consultants
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2006 Annual Report

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